Environmental Protection Agency

Comment 1: Purpose/Legal Authority, last paragraph, p. 3: We note that the Coyote Station Permit to Construct is contained in Appendix A not Appendix D. Please clarify.

Response: The reference will be clarified to indicate the Coyote Permit to Construct is in Appendix A.

Comment 2: Tables 6.3 and 6.4, pp. 41-42: The NO_x emissions inventory for 2018 has been changed from previous versions reviewed. Please explain this change. It appears the point source number was revised downward to include projected emissions reductions from the Coyote Station. If so, we note that the Coyote Permit to Construct doesn't require compliance with the revised NO_x limit until July 1, 2019. Therefore, it is not appropriate to include the reduction in the 2018 inventory.

Response: The installation of the separated overfire air will be completed by July 1, 2018 or earlier. Based on our experience with the M.R. Young Station, the effects in reducing emissions should be immediate. By the end of 2018, we believe the NO_x will be reduced to the level of the Permit to Construct. Since we are indicating the reductions that will be achieved by this SIP revision, we believe it is appropriate to include the reductions from Coyote.

Comment 3: Exclusion of Montana Dakota Utilities Heskett Unit No. 2, p. 66-68:

(A) Table 7.2 – This table will need to be revised to include updated 98^{th} percentile visibility impact results based on approved modeling.

(B) We are in the process of reviewing MDU's December 17, 2009 revised modeling report. EPA will provide additional comments on this issue if the revised modeling fails to address our concerns. See comment #21 below for more detail.

Response:

(A) Agreed

(B) No response necessary. It is the Department's understanding that EPA agrees that Heskett Unit 2 is exempt from BART.

Comment 4: Section 7.4.2, Department BART Determinations, p. 69-77: The modeling to determine if each BART-eligible source has a significant impact on visibility was performed by NDDH using the CALPUFF model following EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts specified in the Guidelines for BART Determinations Under the Regional Haze Rule, 40 CFR Part 51, Appendix Y. However, NDDH conducted an alternative cumulative visibility modeling approach in the NO_x BART determinations for M.R. Young and Leland Olds because it believes single source modeling results "tend to be five to seven times larger" than results when the same source is combined with all other sources in a cumulative analysis (although for other pollutants that affect visibility - PM and SO_2 - it appears that the State used the single source method contained in the BART Guidelines). The basis for NDDH's belief is that the perceived change in visibility from controls on a single source is reduced when background contributions from other sources are included in the modeling.

EPA does not agree that the single source modeling under the BART Guidelines overstates the degree of visibility improvement from emission reductions at the source. The Clean Air Act establishes a National goal of eliminating man-made visibility impairment from all mandatory Class I Federal areas. Use of a clean background (*i.e.*, not considering other nearby sources) is consistent with the ultimate goal of the program to reach natural background conditions. Moreover, the consistent use of a clean background in BART evaluations in North Dakota and surrounding states will foster emission reductions that will speed achievement of natural background conditions, and will ensure equity among states in achieving this goal. The NDDH has already modeled the 98th percentile values using the BART Guidelines' methodology for evaluating visibility improvements from the various control options. These values need to be used when weighing the visibility benefit factor in the NO_x BART analyses.

In addition, North Dakota has noted elsewhere that "according to the Regional Haze Rule, the focus of visibility improvement demonstrations is the 20% worst visibility days, not the cleanest days." This statement is contradicted by several provisions in the Regional Haze Rule that call for assessment of both the most and least impaired days. See, *e.g.*, 40 CFR 51.308(d)(2), (f)(1), and (g)(3).

Response: The Clean Air Act in Section 169A(g)(2) states: "in determining best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, **and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology**;" [emphasis added]. We believe the cumulative modeling provides a much more accurate estimate **of the degree of improvement in visibility which may reasonably be anticipated to result from the use of SCR**.

The difference between cumulative and BART single-source modeling results starts with the logarithmic relationship between deciview and light extinction, which is based on the proven concept that an observer will detect visibility changes more easily in clean air than in dirty air. Deciview is related to light extinction using the equation

$$dv = 10 \times \ln(b_{ext} / 10)$$

where

dv = deciview

b_{ext} = light extinction in units of inverse mega-meters (Mm^{-1})

In BART single-source modeling, the incremental impact of the subject source is based on a background of natural visibility conditions only. In cumulative modeling, as conducted by WRAP, the incremental impact of the subject source is based on a background of natural visibility conditions plus the impact of a complete inventory of all other source emissions which affect visibility. Therefore, calculated delta-deciview for the subject source for the cumulative case will be lower than for the single-source case.

A simple hypothetical example can illustrate the difference in single-source and cumulative visibility modeling. Assume that a subject source is contributing 5 Mm^{-1} to total light extinction and that the natural visibility background is 20 Mm^{-1}. Under single-source modeling, delta-deciview for the subject source would be calculated:

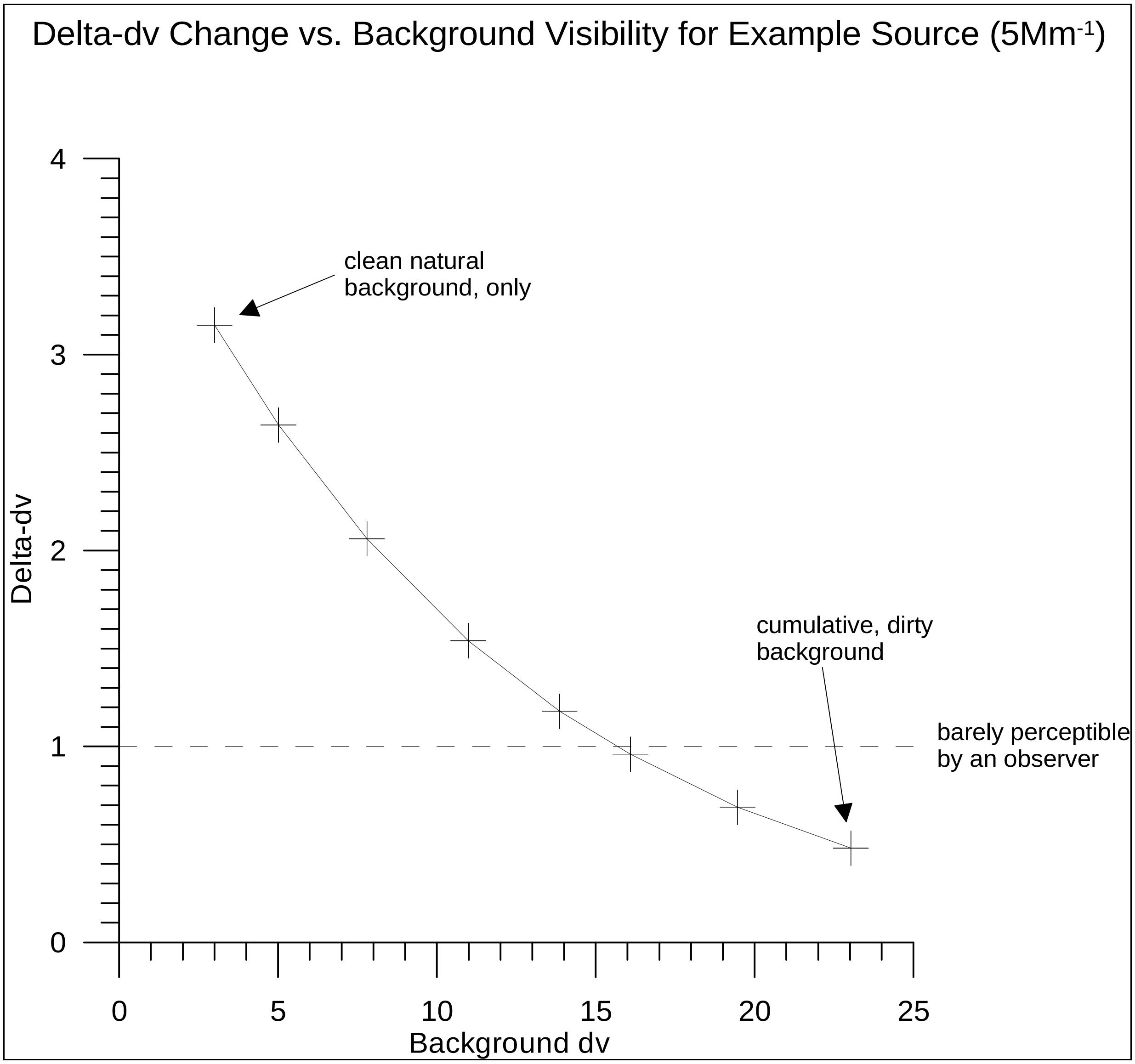
delta-dv = [10 x ln(25 / 10)] – [10 x ln(20 / 10)] = 9.16 – 6.93 = 2.23

WRAP and the NDDH have found that adding a complete emissions inventory in the cumulative modeling will typically result in a background more than double the natural visibility conditions. So to complete the example for the cumulative modeling case, we assume a background of 50 Mm^{-1} and the same subject source. Delta-deciview for the subject source would be calculated:

delta-dv = [10 x ln(55 / 10)] – [10 x ln(50 / 10)] = 17.05 – 16.09 = 0.96

Therefore, inclusion of the complete visibility-affecting emissions inventory in the cumulative modeling produces a smaller, but more realistic, observer-detected difference of 0.96 deciview from the subject source. In fact, for this example, the cumulative modeling result falls below the generally recognized observer-detectable threshold of about 1.0 deciview. Thus, the example illustrates that the impact of the subject source plume against a clean background would be much more noticeable to an observer than the impact of the same plume against the more realistic dirtier background. And, obviously, any change in visibility-affecting emissions from the subject source would have a smaller impact on the observer under the cumulative modeling scenario.

In the figure below, delta-deciview has been plotted for several background deciview levels, based on the subject source, above. The included background levels range from a clean natural background to a dirty background representing the cumulative effect of many visibility-affecting sources. The plot includes the two points calculated above. The plot illustrates the general dependency of the observed visibility change (delta-deciview) on the background level, and the fact that an observer’s perception of visibility change can vary greatly depending on the background deciview level. In fact, for this example, there is a factor of 6.6 difference in delta-deciview for the cleanest background compared with the dirtiest background (3.15 / 0.48 = 6.56).



To further illustrate the difference in single-source and cumulative visibility analyses, the NDDH conducted additional modeling using actual sources. For this illustration, the NDDH grouped the BART-applicable Coal Creek, Leland Olds, and Milton R Young Generating Stations (in North Dakota) as an effective single source. Single-source and cumulative modeling analyses were conducted to determine the incremental visibility improvement at Theodore Roosevelt National Park from the 3-source group, based on BART controls. Calpuff system versions 5.8, the new IMPROVE equation, annual average natural background, and consistent annual emission rates (for the three noted sources) were applied for both analyses. The 90^{th} percentile visibility day from the single-source modeling results was used to emulate the 20% worst day average from the cumulative modeling results. (Given that the typical distribution of 20% worst day visibilities tends to be skewed toward the high end, the 90^{th} percentile day may somewhat understate the 20% worst day average). Note that the post-BART emissions inventory for the cumulative analysis included changes only to the three sources referenced above.

Results of the NDDH modeling analyses are summarized in the table below. The modeling analyses discussed above are compared in the first two columns of results.

	20% Worst Day Avg. Cumulative Modeling	90th Percentile Day Single-Source Modeling	90th Percentile Day Single-Source Modeling Using 2005 ND BART Protocol
Baseline (dv)	16.954	6.552	5.583
Post-BART (dv)	16.493	5.641	3.288
Improvement (delta-dv)	0.461	0.911	2.295

As shown in the table, visibility improvement from the addition of BART controls to the three generating stations based on single-source modeling is about twice that found from cumulative modeling. These results are consistent with the hypothetical example discussed above.

Also shown in the table are results of a third modeling scenario, i.e., single-source modeling based on the North Dakota BART modeling protocol. Consistent with EPA recommendations at the time (2005), the North Dakota BART protocol specified the use of Calpuff Version 5.7, the old IMPROVE equation, and a natural background reflecting cleanest days. In addition, the protocol specified use of maximum 24-hour emission rates, per the BART Rule. As indicated in the table, use of this protocol resulted in a much greater "apparent" improvement in visibility, about a five-fold increase in the result from the cumulative modeling. This illustration, therefore, is another basis for the NDDH statement in the SIP that BART single-source modeling over predicts by a factor of 5 to 7.

All BART modeling conducted by the NDDH and industry was based on the North Dakota BART protocol. Given differences in the North Dakota BART protocol (compared to later protocols), combined with the logarithmic nature of the relationship between deciview and light extinction, it becomes clear that BART single-source modeling could have greatly overstated the more realistic results obtained from recent cumulative modeling for North Dakota.

Note that use of the ND BART single source modeling produces a visibility improvement at Theodore Roosevelt National Park (2.295 dv) which achieves compliance with the uniform rate of progress goal (2.3 dv as discussed in Section 5 of the North Dakota SIP). If one was to accept the premise that these single-source modeling results are realistic, it would logically follow that North Dakota has met the uniform rate of progress based on BART controls for the three modeled sources, and that the need to address additional (non-BART) visibility-affecting emissions reductions in North Dakota is therefore less compelling.

The 20% worst-day average metric from cumulative modeling and the 90th percentile day metric from single-source modeling have been compared in this illustration as they constitute a comparable moment of the annual distribution of daily visibility predictions. Obviously, the 98th percentile day metric from single-source modeling would provide an even greater exaggeration of actual visibility change than the 90th percentile, in the context of the 20% worst-day average metric required to measure progress with respect to visibility goals under the regional haze rule.

The Leland Olds Station and M.R. Young Station are not subject to the BART Guideline (see response to Comment 43.B regarding the M.R. Young Station). In the BART Guideline (40 CFR 51, Appendix Y, Section I.H) it states "For sources other than 750 MW power plants, however, states retain the discretion to adopt approaches that differ from the guidelines." The Department is exercising this discretion for these sources since the cost of SCR is very high on a dollar per ton basis and on incremental cost basis. Therefore, the cumulative visibility modeling results were weighted significantly in our decision not to require SCR.

Comment 5: SO_2 BART section, p. 71: The SO_2 BART determination for Stanton Station Unit 1 may result in too high a limit when burning Powder River Basin (PRB) coal. Please see our Comment #49 below for more detail.

Response: See response to Comment 49.

Comment 6: NO_x BART section, p. 73: We do not agree that SNCR satisfies the BART requirements for Leland Olds Unit 2 and M.R. Young Units 1 & 2. See our comments below on the related BART determinations.

Response: See response to Comments 22-25, 27, 31-33.

Comment 7: Section 8.5.1, Hybrid Modeling System, pp. 95-96: The NDDH utilized a hybrid modeling approach for determining the status of its Class I areas with respect to the rate of progress visibility goals. This approach involved nesting a local NDDH CALPUFF modeling domain within the WRAP National CMAQ domain, and applying the CALPUFF model in a retrospective sense to more realistically define plume geometry for local point sources. The hybrid modeling results were used in a weight of evidence analysis to evaluate the effect of emission sources located outside of North Dakota. Please note that the last version of this modeling protocol to be reviewed by EPA was a draft dated April 2007 (*i.e.*, we never received the final October 2008 version for review). As modeling science has improved, there have been a number of technical changes in the CALPUFF modeling system and EPA/FLM recommended default settings since NDDH proposed the CMAQ/CALPUFF hybrid modeling approach in 2007. In the Reasonable Progress modeling, the hybrid CALPUFF/CAMx modeling results were adjusted based on IMPROVE monitoring data, and it is not clear whether the use of these obsolete settings affected the weight of evidence factors or the Reasonable Progress demonstration. The settings NDDH used in the CALPUFF model within the hybrid modeling system would not be considered technically sound if contained in a regulatory modeling protocol for a future project. However, in this instance it does not appear to have made a difference since North Dakota is not able to meet the uniform rate of progress with either the WRAP analysis or NDDH's hybrid modeling system.

Response: EPA was sent the final October 2008 version of the modeling protocol. The protocol was sent by email from Steve Weber to Kevin Golden on October 6, 2008 (see attached copy of this email).

As discussed in Section 8.5.6, the NDDH ultimately applied its hybrid modeling system to adjust or add value to WRAP CMAQ visibility modeling results, rather than as a stand-alone tool for absolute visibility projections. The adjustment is based on a correction where hybrid CMAQ-CALPUFF model output is involved in both the numerator and denominator of the correction factor (fraction). Therefore, the effects of the NDDH alternative CALMET/CALPUFF technical settings (reflected in both numerator and denominator model output) would have largely "cancelled out" when the correction factor was applied. In fact, had the CALMET/CALPUFF technical settings been reset to be completely consistent with EPA recommendations, it is not likely the correction factor would have meaningfully changed.

Comment 8: Section 8.6.1, Hybrid CMAQ-CALPUFF Performance Evaluation, p. 132, 1st paragraph, 1st sentence: Model performance was tested for the 90th percentile days. In addition, NDDH needs to compare performance on the 98th percentile day consistent with the BART metric.

Response: Section 8.6.1 has been revised to include hybrid model performance for the 98th percentile day.

Comment 9: Section 8.6.2.3, Apportionment by Source Group, pp. 146-153: We note that focus was on North Dakota EGUs and boundary condition groups due to their relatively "small" and "large" contributions, respectively. Since NDDH needs to be looking at what is within its control, North Dakota EGUs become the largest contributors. We also note that North Dakota's NO_3 percent contribution in 2018 actually increases at LWA (Table 8.16, p. 152), so it appears that there may be additional NO_x sources within North Dakota's control that can be addressed. This increase may be related to increased oil and gas development in the area.

Response: As we noted in the SIP, we believe WRAP has overestimated the increase in NO_x emissions from oil and gas production activity in North Dakota. Although the percent contribution for the North Dakota sources increases in 2018, the actual contribution ($\mu g/m^3$) and the total contribution of all sources decreases by 2018. The only area which increases the actual contribution to nitrates ($\mu g/m^3$) in LWA is Canada (see WRAP TSS).

Comment 10: Section 8.6.2.5, Conclusions, pp. 156-157: NDDH concludes that while the addition of proposed BART controls will substantially decrease the visibility impact of North Dakota EGUs, these EGUs comprise only a small component of total 20% worst day impacts at TRNP and LWA. The text needs to also note that during periods when EGU emissions are transported into the Class I areas, the proposed BART reductions will significantly improve visibility. This can be demonstrated by referencing the peak day and 98th percentile CALPUFF results for each EGU.

Response: Even though modeling demonstrated that North Dakota EGUs comprise only a small component of general 20% worst-day average impact at TRNP and LWA, the NDDH acknowledges that BART reductions from these EGUs likely resulted in substantial visibility improvement on certain worst days with favorable meteorology. Language has been added to the conclusions in Section 8.6.2.5 to facilitate this acknowledgement.

Comment 11: Section 9.5.1, Step 1, pp. 177-181: We have several comments related to this section. First, please note that the Q/D approach does not work for sources like Oil & Gas where the emissions are spread out over large areas, but cumulatively the emissions and impacts from these sources can be significant. In addition, the narrative needs to acknowledge the potential impact of primary PM if emissions are large. Next, please note that the reference to the BART Guidelines under the Q/D discussion is not necessarily applicable for Reasonable Progress purposes. Lastly, it appears that Heskett Station Unit 2 was omitted from the sources reviewed in Table 9.4. Please clarify.

Response: The Q/D analysis can work for certain oil and gas facilities such as compressor stations or natural gas processing plants. We agree it would not work well for oil production or development facilities. This has been added to Section 9.5.5.

With regard to oil and gas production and development emissions of particulate matter, both the Department and WRAP agree that emissions will be very small. The only emissions that are not covered in other source categories would be fugitive emissions from road and well pad construction. These emissions are short duration (a few days or less) and are subject to the fugitive dust control requirements in NDAC 33-15-17. As can be seen from Table 6.1 and 6.3, road dust emissions, which includes emissions associated with oil and oil development and production, are not expected to increase from 2002 rates. We do not anticipate any significant increase in visibility degradation due to PM emissions from oil and gas production activities.

Regarding the Q/D discussion for exemption from BART, we believe this is highly relevant. When the visibility impact of a source is so small it can be exempted from BART, additional controls under reasonable progress are likely not to be cost effective on a dollar per deciview basis.

Heskett Unit 2 will be added to Table 9.4.

Comment 12: Section 9.5.1, Table 9.8, p. 184:

(A) As noted in our August 12, 2009 preliminary comments on the WRAP's May 18, 2009 Draft *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota,* the reliance on a 1982 NSPS analysis for Claus Sulfur Recovery Units raises questions regarding why newer data could not be utilized. Advancements in energy efficient technology and heat transfer media may affect tail gas treatment unit operational needs. Current data should be available and may indicate lower energy and steam usage. Please verify that these concerns with the WRAP report were not carried over into the North Dakota SIP.

(B) There appear to be numerous NO_x controls available at costs similar to, or less than, those selected under BART, raising the question of why Antelope Valley and Coyote Station warranted a decision by NDDH that NO_x controls carry excessive costs. Since NDDH has already determined BART controls - similar to the control options analyzed for the Reasonable Progress units - to be cost effective and to provide visibility improvement, it is unclear how similar controls on the EGUs at Antelope Valley and Coyote Station would not be justified.

(C) Some average cost effectiveness figures are lower for control options that provide greater reductions, *e.g.*, Low NO_x Burners (LNB)+SNCR at Antelope Valley Units 1 & 2 and Low-Emission Combustion (LEC) Retrofit at Tioga Gas Plant's five 1920 hp reciprocating engines. The clear advantage of these options warrants further consideration by NDDH.

(D) The estimated cost effectiveness of control options for Tioga Gas Plant's rebuilt engines (2350 hp) appears to be inaccurate since reductions are underestimated for add-on controls. Despite emission reductions achieved during rebuild, the percent control efficiency should not differ that much from engines that are not currently operating at peak performance. It appears that NDDH relied on the WRAP's May 18, 2009 Draft *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota*, which assumed that "air-to-fuel ratio adjustments, ignition timing retarding, and LEC retrofit would not achieve further emission reductions since the estimated emission reductions for these measures are less than the reductions which appear to have already been achieved." However, the above reductions should have been assumed on top of reductions which appear to have been achieved through rebuild. In addition, the WRAP report indicates that SCR reduces emissions from reciprocating engines by 90%; therefore, NDDH needs to explain its use of 80% for the 1920 hp engines and 50% for the 2350 hp engines. Using an inappropriately low control efficiency will result in a biased high cost effectiveness of a control option.

Response:

(A) EPA has provided no evidence to support their claim that advancements have been made in energy efficiency and heat transfer media. The NDDH believes the cost estimate represents a reasonable representation of the cost of a tail gas clean up unit. Any savings in energy, including steam, will have a minor impact on the annualized costs. We believe the estimate is within the $\pm$30% range of accuracy of the EPA Air Pollution Control Cost Manual recommended by EPA.

(B) In the BART determinations, visibility impacts were given very little weight for SO_2 and NO_x because of the inaccuracy of the BART single source modeling unless the control option had a high cost effectiveness or incremental cost. If cost effectiveness or incremental cost was high, we considered the cumulative type modeling. Had visibility impacts been weighed more heavily, some of the referenced selected BART technologies would not have been chosen. In evaluating reasonable progress, we evaluated the cost on a dollar per ton basis and the amount of visibility improvement (as you have correctly pointed out that the Department can consider). For Antelope Valley Station, all controls will improve visibility in the most impaired days by 0.01 deciviews or less. For the Coyote Station, the improvement is 0.04 deciviews or less and for the Tioga Gas Plant it is 0.05 deciviews or less. The maximum improvement for these facilities combined is 0.11 deciviews at LWA and 0.03 deciviews at TRNP during the most impaired days. To achieve this minute amount of improvement would require an annual cost of 68 million dollars. The Department has concluded that the trivial amount of visibility improvement does not warrant such costs. As pointed out in the SIP, other control options will improve visibility on the most impaired days even less.

(C) The Department did evaluate LNB+SNCR at the Antelope Valley Station and LEC Retrofit at the Tioga Gas Plant (see Tables 9.8 and 9.9). The cost on a dollar per deciview basis and the trivial amount of visibility improvement does not warrant requiring these controls.

(D) In establishing a baseline for calculating the cost effectiveness of a control option, we used the emissions for the 2350 Hp engines after they were refurbished since it represents current normal operations for these engines and anticipated future emissions. You cannot ignore money that has been spent to reduce emissions before the reasonable progress analysis began or was ever envisioned. To do so would provide an artificially low cost for additional reductions and is contrary to the methodology for making BART and BACT determinations.

The WRAP Report dated May 18, 2009 lists an efficiency of 80-90% in Table 4-1 for the 1920 Hp engines. Table 4-2 lists an efficiency of 80%. The NDDH has determined that 80% is more reasonable for emission limits that must include startup, shutdown and malfunctions. For the 2350 Hp engines, the WRAP Report lists a range of 33-67% (see Table 4-2). The NDDH determined the middle of the range was appropriate for these engines that are emitting 70% less NO_x than the engines that were not refurbished.

Comment 13: Section 9.5.1, Step 3, p. 183-185: Visibility improvement is not one of the four Reasonable Progress statutory factors (cost of compliance, time necessary for compliance, energy/non-air quality environmental impacts of compliance, and remaining useful life of any potentially affected sources), but the State has the flexibility to consider it in decision-making. The State selected a number of emission units for potential Reasonable Progress controls; however, as shown in Table 9.9, NDDH may have eliminated these from consideration due to a perceived small visibility improvement attributed to each control measure. The cost effectiveness ($/ton) for reducing emissions at a number of the sources considered for Reasonable Progress controls is similar to the cost effectiveness that NDDH considered appropriate for control at the BART sources. Thus, it is reasonable to consider controlling these sources as well. The relatively low visibility benefit for controlling an individual unit should not be a major factor to consider when selecting Reasonable Progress measures; given the ultimate purpose of the Regional Haze program, cumulative effects across sources need to be considered. In addition, since NDDH has chosen to rely heavily on visibility improvement for its decisions on Reasonable Progress controls, we consider it important to include the 98th percentile day results in addition to the 20% worst days results. In our view, since the 98th percentile day results are used in determining BART, and NDDH has chosen to rely on visibility improvement in determining Reasonable Progress controls, it makes sense to include the 98th percentile day results under Reasonable Progress to supplement the 20% worst days results.

Response: The purpose of the Regional Haze program is to improve visibility. The Department considers this purpose in its decision making process. EPA, in this comment, acknowledges that a state has the right to consider the amount of visibility improvement. Because of the purpose of the rule, visibility improvement has weighed heavily in our determinations on reasonable progress. (See our discussion in the response to Comment 12B on how visibility was weighed for the BART determinations.)

In 40 CFR 51.308(d) it states "The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 states "most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment." Least impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment. Because of the reasonable progress requirements and the regulatory definitions, we believe 98th percentile values for visibility improvement are inappropriate.

The maximum amount of improvement that would be achieved by the top controls listed in Table 9.9 is:

Source	TRNP*	LWA*
AVS (each unit)	0.028%	0.051%
Coyote Station	0.112%	0.205%
Tioga Gas Plant	0%	0.255%

* Calculated from the baseline visibility conditions.

If the top technologies from Table 9.9 are assessed cumulatively, the improvement would be 0.169% at TRNP and 0.561% at LWA. The Department considered this amount of improvement to be inconsequential. The other technologies evaluated would provide even less improvement. The capital cost to provide this much improvement is estimated at 243 million dollars with an annualized cost of over 68 million dollars. The cost effectiveness is over 618 million dollars per deciview at LWA and 2.3 billion dollars per deciview at TRNP. EPA's Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) states "Therefore, in assessing additional emissions reduction strategies for source categories or individual, large scale sources, a simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation... ." It appears EPA is ignoring its own guidance by dwelling on the dollar-per-ton cost effectiveness and ignoring the dollar-per-deciview cost effectiveness. We stand by our decision not to require additional controls.

Comment 14: Section 9.5.1, Time Necessary for Compliance, p. 185: As noted in our August 12, 2009 preliminary comments on the WRAP's May 18, 2009 Draft *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota*, this timeline for compliance seems to be overestimated and/or doesn't account for steps that can be completed in parallel. In addition, the time necessary for compliance should not include time to develop regulations. If new regulations are necessary, such regulations need to be submitted with the forthcoming SIP. The WRAP report indicated that two years may be needed to develop the rules to implement Reasonable Progress strategies. This statement implies that the State lacks authority to develop and submit a SIP to address Reasonable Progress and Long-Term Strategy requirements, including relevant Reasonable Progress measures. Please verify that these concerns with the WRAP report were not carried over into the North Dakota SIP.

Response: The Department has stated that up to 6½ years would be needed to implement any additional controls. In the case of the Coyote Station it may be longer depending on when that portion of the SIP is approved. The Department believes it can issue Permits to Construct for the Coyote Station and Heskett Station that contain requirements to reduce emissions. However, we believe the full-time frame listed in the EC/R report is reasonable.

Comment 15: Section 9.5.1, Reasonable Progress Goals – Required Controls for Point Sources, p. 186-187: Again for comparison, since NDDH has chosen to rely on visibility improvement in determining Reasonable Progress controls, it is appropriate to also provide and consider the 98th percentile day results in aggregate. In addition, given that the cost effectiveness ($/ton) for reducing emissions at a number of the sources considered for Reasonable Progress controls is similar to, or less than, the cost effectiveness that NDDH considered appropriate for control at the BART sources, it is unclear why some additional Reasonable Progress controls are not warranted in the current planning period.

Response: See responses to Comments 12B and 13.

Comment 16: Section 9.5.4, Coyote Station, p. 189: It appears that NDDH believes at least this minimal level of control is reasonable now. As such, why isn't it included as a required Reasonable Progress control in the SIP? Further, why is the related Permit to Construct contained in Appendix A, BART Modeling Protocols and Analyses? Finally, this "agreement" must not preclude NDDH's re-evaluation of this source in future planning periods.

Response: The Department determined under the Reasonable Progress Analysis that no additional controls were required at the Coyote Station. Although no additional controls are required by rule or law, we have reached an agreement with the owners of the plant to reduce NO_x emissions even though no visibility improvement will be realized. To avoid any precedent for other sources under the Reasonable Progress analysis, the Coyote discussion is not included under the Point Sources Section (Section 9.5.1). The discussion regarding the Coyote Station has been relocated to Section 10.6.1, Emissions Reductions Due to Ongoing Air Pollution Control Programs.

Comment 17: Section 9.6, Visibility Modeling and Weight of Evidence, p. 191-193: The statement that implementing additional controls at Antelope Valley Station, Coyote Station, and Tioga Gas Plant "will not significantly affect current visibility conditions or the amount of time necessary to achieve natural conditions" – is misleading. Visibility improvement in aggregate should result in more progress. These sources are within NDDH's control (as opposed to the Canadian sources) and are cost effective to control. We understand that NDDH is not able to meet the uniform rate of progress in this planning period, but this does not justify the lack of Reasonable Progress controls on these sources.

Response: We strongly disagree with your assertion that the statement that additional controls at the Antelope Valley, Coyote Station and Tioga Gas Plant "will not significantly affect current conditions or the amount of time necessary to achieve natural conditions" – is misleading. As pointed out in the response to Comment 13, application of the most efficient cost effective ($/ton) controls will only produce a 0.169% improvement in visibility during the most impaired days at TRNP and 0.561% at LWA. The amount of time to achieve natural conditions would decrease from 156 years to 151 years at TRNP and from 232 years to 201 years at LWA. We stand by our statement.

As for requiring controls, see the Response to Comments 12B and 13 and our Reasonable Progress analysis with the SIP.

Comment 18: Table 9.14, Reasonable Progress Goals, p. 195: The addition of the goals based on WRAP's modeling approach is useful; however, clarification should be provided as to which goals are being established by NDDH.

Response: The SIP has been revised to indicate the Reasonable Progress goals are based on the Department's modeling.

Comment 19: Section 10.6.5, Smoke Management Techniques for Agriculture and Forest Management, pp. 204-205: A statement needs to be added that NDDH will re-evaluate potential emissions reductions on sources within North Dakota's control in future planning periods.

Response: Agreed

Comment 20: Section 11.6, Rules for Non-BART Point and Area Sources, p. 213: Although NDDH has determined that it is not reasonable to control these sources during the current planning period, this section implies that NDDH lacks authority to develop and submit a SIP to address Reasonable Progress and Long-term Strategy requirements, including relevant Reasonable Progress measures. It is not appropriate to use this lack of authority as justification for elimination of Reasonable Progress controls in the current planning period nor is a commitment of this nature acceptable to address requirements.

Response: The Department has not used the lack of clarity regarding implementation of controls on non-BART sources as a reason for not requiring control. The reasons for not requiring control are based on the four statutory factors (see Section 9.5.1 of the SIP and our response to Comments 12B and 13). Since our analysis of the four statutory factors indicated additional controls were not reasonable, we had no reason to clarify our authority for these controls. Before the next review period, the NDDH's authority will be clarified.

<u>Comment 21</u>: Appendix A.2.2, AECOM's August 12, 2009 Response to Concerns Regarding BART Exemption Modeling for Heskett Unit 2:

(A) NDDH's 2006 CALPUFF BART exemption modeling indicated that baseline emission impacts would result in a visibility impact of 0.82 deciviews (dv) at TRNP and 0.58 at LWA. Predicted visibility impairment exceeding 0.5 dv would make the facility subject-to-BART. MDU then contracted with ENSR to make refinements to the State's analysis that included reducing the grid size from 3 km to 1 km and a number of other settings in the model that are not consistent with current EPA defaults settings for the CALFUFF model. To address this issue, in November 2009 NDDH, EPA, MDU, and the FLMS negotiated a modeling protocol that involved rerunning the model for BART applicability using the current EPA default model settings. MDU recently completed the revised modeling and provided the results in a December 17, 2009 report. The results show that the facility is exempt from the BART requirements. EPA has obtained and is reviewing the modeling files to verify these results. Given that this updated modeling was completed after the start of the current public comment period on the Regional Haze SIP, EPA will provide additional comments on this issue if the revised modeling fails to address our concerns. Please note that NDDH will need to revise the SIP to include the revised modeling and your related conclusions. The revision will need to follow North Dakota's public participation process for SIP revisions.

(B) We also note an inaccurate reference in Appendix A.2.2 stating that EPA accepted Rapid Update Cycle (RUC) prognostic meteorological data for use in NDDH's SO_2 Periodic Increment Review. EPA has not taken action to approve NDDH's Periodic Increment Review.

<u>Response</u>:

(A) The Department believes MDU Heskett Unit 2 is exempt from the BART requirements and apparently EPA now agrees with that determination. The source will be reviewed under the Reasonable Progress requirements. An initial review of this source indicates a 95% reduction in SO_2 (wet scrubber) and a 40% reduction in NO_x (SNCR) will produce a visibility improvement of only 0.009 deciviews at TRNP and 0.003 deciviews at LWA during the most impaired days. It is unlikely that any additional controls will be required.

(B) We acknowledge that final action has not been taken.

<u>Comment 22</u>: Appendix B.5, BART SCR Technical Feasibility Analysis for North Dakota Lignite:

(A) While we agree with your determination that Low Dust SCR and Tail-End SCR are technically feasible, we do not agree with all of the technical aspects or conclusions of the analysis, especially as they relate to High Dust SCR. As you know, we have done a thorough review of the technical feasibility analyses submitted by Minnkota for Units 1 and 2 at Milton R. Young Station and NDDH's preliminary BACT determination published for public notice on June 11, 2008. Our comments and supplemental information were provided in previous letters from EPA Region 8's Office of Enforcement, Compliance, and Environmental Justice, to the North Dakota Department of Health, Division of Air Quality. Our letters provided substantial information and evidence that all SCR technology, including High Dust SCR, is technically feasible at facilities burning North Dakota lignite, and we continue to stand by those comments.

(B) Please see p. 8 of the Institute of Clean Air Companies (ICAC) May 2009 White Paper on SCR Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants, contained in Enclosure 3 for your use. This paper addresses feasibility of SCR on lignite-fired boilers and, while noting "[l]ignite from different mines has some common characteristics but also differs in some significant ways," states that "[w]ith proper design, lignite applications can be successful." The ICAC paper addresses the technical issue of high sodium in lignite and states that "[t]hese poisons are not an issue as long as the catalyst stays above dew point conditions."

<u>Response</u>:

(A) We stand by our response that HDSCR is not technically feasible for North Dakota lignite. The preponderance of the evidence indicates HDSCR cannot be successfully operated on North Dakota lignite and is, therefore, not technically feasible.

(B) This White Paper was developed by companies that are in the business of selling air pollution control technology. Therefore, their statements must be evaluated carefully and proper consideration given to the source. The White Paper states "These poisons [Na/K] are not an issue as long as the catalyst stays above dew point conditions." This is in direct contrast to Zheng, et. al., (2008) that found that the submicron Na and K aerosols migrate into the catalyst pores by diffusion, most likely surface diffusion, with temperatures above the dew point. Zheng, et. al., found rapid catalyst deactivation under normal operation conditions. This statement is also in conflict to experience with biomass boilers. Under normal operating conditions (i.e. above the dew point) rapid catalyst deactivation has been found. Most, if not all, biomass boilers are now equipped with tail-end SCR (e.g. Amager Station). Ceram, in Minnkota's response to questions about the SCR cost estimate (2/11/10), states "Small aerosol particles can penetrate and neutralize active catalyst sites even in dry conditions." Ceram also stated "Catalyst installed in even low dust and tail-end locations are poisoned from the exposure to the flue gas" and "moreover, the high levels of phosphorus, sodium and potassium found in the mineral analysis will increase deactivation rates." It is also in direct conflict with the Minnkota efforts to secure a catalyst guarantee for a tail-end or low-dust SCR. Two companies, Ceram and Haldor Topsoe, refused to offer guarantees without previous pilot-scale testing.

The White Paper does not state which type of SCR (HDSCR, LDSCR, or TESCR) will be successful with proper design. The Department has determined that only LDSCR and TESCR will be successful. The Department's opinion may not be in conflict with the White Paper; the White Paper is just not specific enough for any determination to be made.

Comment 23: Appendix C.1, Leland Olds SCR Cost Estimate: We have numerous concerns with the May 2009 Leland Olds BART Update, Tail-End Selective Catalytic Reduction (TESCR) Cost Effectiveness Evaluation, as prepared by Sargent & Lundy for Basin Electric and utilized by NDDH in its BART determinations for Leland Olds. In summary, several unsubstantiated and likely inappropriate assumptions impact the cost effectiveness numbers relied upon by NDDH to eliminate SCR in its BART determinations for Leland Olds Units 1 & 2. These assumptions result in calculated costs for TESCR that are biased high. If a more reasonable set of assumptions are incorporated into this analysis, it will likely show SCR to be cost effective on the cyclone unit (Leland Olds Unit 2), and it may also be cost effective for the wall-fired unit (Leland Olds Unit 1). Please see our detailed comments in Enclosure 2.

Response: For making cost estimates for control technology review, the BART Guideline recommends the EPA Air Pollution Control Cost Manual (EPA/452/13-02-001). However, the manual cannot be used for determining the cost of TESCR (Section 2.4 for Selective Catalytic Reduction). Although the Control Cost Manual cannot be used for TESCR, it does provide a statement on the accuracy of the cost estimates generated by the manual. Chapter 2, Section 2.2 states "As mentioned in Chapter 1.1, the costs and estimating methodology in this Manual are directed toward the "Study" estimate with a nominal accuracy of ±30% percent." We believe Basin Electric's estimate is within ±30%. With the respect to the specific comments:

(A) Steam for reheat.

Basin Electric has indicated that using steam for reheat in North Dakota winters represents unique challenges that would greatly increase operation and maintenance costs and downtime. A steam reheat system would have to be designed for -40°F temperatures plus the operator must have the capability to service the system in the harsh conditions of a North Dakota winter. As indicated by Minnkota, their previous experience with the reheat of the flue gas from Unit 2 using steam was not positive and was abandoned. The Department believes this experience is directly applicable to Leland Olds Station.

There is no indication that the units at Leland Olds are turbine limited. Therefore, using steam could have an electrical penalty for the units. For Unit 2, this could amount to nearly 5 million dollars per year.

(B) Engineering calculations should be able to provide a reasonable estimation of the cost within an accuracy of +/-5%.

This statement is contrary to the BART Guideline which recommends using the Control Cost Manual which has an accuracy of ±30%. Perry's Chemical Engineer's Handbook describes five levels of cost estimates 1) Order of Magnitude, 2) Study with an accuracy of ±30%, 3) Preliminary with an accuracy of ±20%, 4) Definitive with an accuracy of ±10%, and 5) Detailed with an accuracy of ±5%. Detailed cost estimates require final drawings, specifications and site surveys. In order to achieve a ±5% accuracy, detailed engineering analyses including plans and specifications for the SCR system will have to be prepared. The BART Guideline does not require this level of detail.

(C) The operating life of TESCR catalyst can be expected to be in the range of 50,000 hours.

Minnkota was unable to secure any guarantee for the life of a TESCR catalyst. EPA's expected catalyst life appears inconsistent with at least two catalyst/SCR vendors. Without pilot scale testing, no definitive statement regarding catalyst life can be made.

(D) Only when the catalyst in the TESCR is being cooled down to below the water dew point, such poisoning will occur.

See response to Comment 22. In Haldor Topsoe's paper entitled "The Influence of Biomass Burning in the Design of an SCR Installation" they indicate that the tail-end installation after a wet FGD will only minimize the amount of poisoning species entering the SCR. To counter this poisoning, Haldor Topsoe used four counter measures to minimize risk. These included a "bio-optimized" catalyst with a high vanadium content and a high number of active sites to make the catalyst less susceptible to poisoning by alkali metals. All of this indicates that poisoning of TESCR catalyst is a real concern especially with organically associated sodium and potassium.

EPA claims that the wet scrubber will mostly absorb the sodium and potassium aerosols in the acidic scrubber slurry. This statement is in conflict with data from Markowski et. al. (1983). Markowski's data indicates the wet scrubber at M.R. Young Unit 2 does not remove the submicron sodium and potassium aerosols that cause SCR catalyst deactivation. The data actually suggests an increase in submicron aerosols. Based on this data, the Department believes a wet scrubber that is designed for sulfur dioxide control will have little effect on the sodium and potassium submicron aerosols. However, the Department agrees that the sodium and potassium aerosol concentration entering either a LDSCR or TESCR will be sufficiently low to allow successful operation.

(E) The Leland Olds LDSCR and TESCR systems would be similar to the M.R. Young systems. Minnkota, in their detailed response to questions by the NDDH and EPA (2/11/10), has responded to this same issue. The SCR process consultant for Minnkota calculated a temperature gradient of 43-45°F. The catalyst vendor recommended a design up to 600°F. Based on 50°F temperature gradient and a heat input of 5120 x 10^6 Btu/hr for Unit 2, Basin Electric has estimated that reheating the flue gas will consume approximately 115 x 10^6 Btu/hr. Minnkota has estimated, based on a temperature gradient of 43°F and a heat input of 4885 x 10^6 Btu/hr, that 96.2 x 10^6 Btu/hr will be required to reheat the flue gas for Unit 2. The difference is attributable to the 7°F temperature gradient difference and the difference in heat input to each unit. Since final design specifications are not required for this estimate ($\pm$30% accuracy required), Basin Electric's estimate of a 50°F temperature gradient and a flue gas temperature of 600°F are reasonable.

EPA claims that the only relevant information from pilot testing would be the catalyst deactivation rate. The Department believes pilot scale testing will also help optimize the catalyst volume that is required; the catalyst surface area required, the required reagent injection rate, expected reagent slip, whether a wet ESP is required for ammonium bisulfate and/or ammonium sulfate emissions and an appropriate catalyst maintenance plan. All of these issues will affect the annualized cost. However, the NDDH believes the cost of LDSCR and TESCR can be estimated, without pilot testing, to within ±30 which is equivalent to the accuracy of EPA's Control Equipment Cost Manual which is recommended by the BART Guideline.

EPA has indicated that two weeks is too much time to replace the catalyst. EPA has suggested that five days would be more appropriate. Assuming 3 layers of catalyst, each layer would contain 177 m^3 of catalyst or approximately 85 modules. Schirmer et. al. in the paper In-Situ SCR Catalyst Replacement indicated it took 9 days to replace 90 modules at the TVA Allen Fossil Plant <u>not including cool down and vacuuming of the reactor</u>. Cool down of the reactor and vacuuming is expected to take 3-4 days. In addition, reheating of the SCR prior to startup will take another 1-2 days. Based on this data, the NDDH believes the S&L estimate of two weeks to replace the catalyst is reasonable.

EPA has questioned the catalyst replacement schedule. Basin Electric has estimated the cost based on a six-month and 12-month replacement schedule. The NDDH believes LDSCR and TESCR will have a replacement schedule that is probably greater than 12 months (10,000 hours equals 13.7 months). Although 12 months is slightly less than the 10,000 hours the Department suggested was necessary for technical feasibility, no one knows the actual deactivation rate without pilot scale testing. Because of the lack of vendor guarantees, a replacement schedule of 12 months appears reasonable. A replacement schedule of 13.7 months would decrease the cost effectiveness by approximately $52 per ton or 1.0 – 1.4%. The Department considers this insignificant. The Department has determined that the cost is excessive at both the low end and high end. The Department also considered the amount of visibility improvement in the BART determination. The amount of improvement between SCR and the next most efficient option is negligible.

Specific issues include:

(A) The catalyst volume of 530 m^3 seems high.

Minnkota has projected a total initial catalyst volume of 768 m^3 for M.R. Young Unit 2 (256 m^3 per layer and 3 layers). M.R. Young Unit 2 is rated at 477 MWe and Leland Olds 2 is rated at 440 MWe. The M.R. Young Unit 2 design volume was provided by a vendor. The DOI, in their consultation comments, estimated that 645 m^3 of catalyst would be required for Leland Olds Unit 2 based on the EPA's Air Pollution Control Cost Manual. Given the Minnkota catalyst volume estimate, the DOI estimate and the uncertainties regarding the catalyst deactivation rate, the catalyst volume appears to be on the low side and therefore acceptable for the cost estimate.

(B) The selected NO_x Efficiency of 85% appears low – see response to Comment 25.

(C) A capacity factor of 92.3% is erroneous since it is based on catalyst replacement every six months.

From 2000-2008 Leland Olds Unit 2 had a capacity factor of 87.4% based on hours of operation. Catalyst maintenance will decrease this availability. Using a capacity factor of greater than 92.3% does not appear to be reasonable based on the operating history.

(D) The price of $7,500 per cubic meter appears high.

This is the same cost provided for the M.R. Young Station which the NDDH understands is based on a vendor quote plus shipping, handling and taxes. It appears the cost is reasonable.

(E) The power cost of five cents per kilowatt appears high.

The Energy Information Administration (EIA) reports that the average retail price of electricity in North Dakota is 6.89 center per kilowatt. They also report that the average wholesale price of electricity in the MRO (formerly MAPP) area was 4.86 cents per kilowatt hour which is the lowest in the country (5.72 cents/kilowatt hour average for the U.S.). The S&L estimate of five cents per kilowatt hour appears reasonable.

(F) Natural gas prices are currently between $3 to $5 MMBtu rather than $8 to $12 MMBtu (inferred that cost of natural gas is too high).

Wellhead natural gas prices have been as much as $14/MMBtu in the recent past. Projecting natural gas prices must take into account the U.S. economy, new legislation or rules for the control of greenhouse gases including the surge in demand for natural gas as a substitute for other fossil fuels to reduce GHG, market price speculation, the ability of supply to keep up with demand and inflationary pressures. The Energy Information Administration (EIA) has predicted that the commercial price will range from $10.65 - $12.12 per MMBtu from 2011-2030 (calculated as 2008 dollars). The NDDH believes $8 - $12/MMBtu is a reasonable estimate of average natural gas prices over the life of the SCR system given the many factors that can influence the cost.

(G) Ammonia costs are currently more in the range of $300-400 per ton rather than $450-700 per ton.

Ammonia costs are directly related to the cost of natural gas since most anhydrous ammonia is produced from natural gas. Based on the NDDH's expectation that natural gas prices will increase, the range of ammonia cost of $450 - $700 per ton is reasonable.

(H) EPA notes that SCR retrofits in the U.S. are well below the $/kw price range calculated by S&L.

EPA provided no details to support this claim. The NDDH notes that Basin Electric's estimate is for TESCR; most SCR installations in the U.S. are HDSCR which have a much lower cost. ERG has noted in their review of the PGE Boardman BART analysis that the cost of SCR has escalated rapidly since 2004. ERG found actual costs exceeding \$267/kw for HDSCR (2007 dollars). For the Boardman Plant, ERG's estimate was \$206 - \$267/kw. The Black and Veatch estimate was \$309/kw. S&L has used \$376-\$387/kw for TESCR which includes a reheat system and gas-to-gas heat exchangers not associated with HDSCR. The NDDH believes the capital cost estimate is reasonable given the uncertainties such as the design volume of the reactor.

<u>Comment 24</u>: Appendix C.4, November 2009 Minnkota Supplemental NO_x BACT Analysis Reports for Units 1 & 2: In response to Minnkota's Supplemental BACT Reports, NDDH sent a November 25, 2009, letter to Minnkota citing a lack of detailed and comprehensive cost data documentation in the Supplemental BACT Reports and the failure to address the use of main boiler steam for flue gas reheat. NDDH requested that this information be submitted, as well as a demonstration that the cost of NO_x removal for SCR is disproportionately high compared to the cost of NO_x control in other recent Best Available Control Technology (BACT) determinations for coal-fired power plants. EPA has reviewed the Supplemental BACT Reports and wholly supports the statements in NDDH's November 25, 2009 letter. Given the fact that you are not satisfied with Minnkota's analysis and have requested additional supplemental information, it is not appropriate to rely on this cost analysis in the BART context at this time. EPA has also identified additional problems and concerns with the Supplemental BACT Reports which must be addressed for BART purposes as well, in accordance with the requirements of 40 CFR 51.308(e)(1). (SIP must include documentation for BART analyses.) These additional problems and concerns are summarized as follows:

(A) The <u>additional</u> outage time estimated in the Supplemental BACT Reports for catalyst cleaning/replacement seems very high and is not supported. Considering there are regular planned outages for both units, these times should be attributed to catalyst cleaning/ replacement activities that would not otherwise be accommodated during these planned outage events.

(B) The estimated catalyst replacement schedule under both scenarios used in the Supplemental BACT Reports is much shorter than EPA would expect for Low-Dust Selective Catalytic Reduction (LDSCR) and TESCR systems. Furthermore, the assumption that one layer of catalyst would be replaced during each planned boiler cleaning outage is made without any justification and should therefore be given little to no credibility in the final conclusions of the BACT analysis.

(C) All vendor correspondence related to catalyst costs and replacement, as described in the Supplemental BACT Reports, must be provided. This includes the original requests submitted to the vendors by Minnkota and/or their consultants.

(D) While the Supplemental BACT Reports give a general description of how the pressure drops and parasitic loads were calculated, Minnkota or NDDH must provide more details, including calculations to justify these high values.

(E) No data is provided for the temperature gradient of the regenerative gas-to-gas heat exchanger, which is essential to determine the required reheat input for either a natural gas-fired or steam system. Furthermore, the assumed value of flue gas reheat of 600 º F must be justified. We would also expect this temperature to be different for a LDSCR and TESCR due to significantly different SO_2 and SO_3 concentrations.

(F) The Supplemental BACT Reports claim there were no similar projects "on coal-fired power plants in the United States that could be used, with adjustments, to properly represent total installed cost" for MRYS. Minnkota or NDDH should consider the data from the PSE&G Mercer and We Energies South Oak Creek facilities that have installed, or will be installing, LDSCR systems.

(G) The cost values used for catalyst, natural gas, and electricity appear higher than current prices and must be substantiated. Furthermore, the Supplemental BACT Reports assume urea would be used as opposed to anhydrous ammonia. Both options should be evaluated and the least costly option selected, unless there is a compelling reason to use the more expensive option.

Response: Minnkota has addressed the use of steam for reheat in their December 11, 2009 response to NDDH questions. The NDDH asked for additional support for Minnkota's position on steam for reheat and several other items. Minnkota has supplied a response to all of the questions the NDDH and EPA posed regarding the cost estimate (2/11/10). The NDDH has reviewed Minnkota's responses and finds them to be acceptable. The NDDH is confident that the range of costs provided by Minnkota have an accuracy of $\pm$30%, which is the accuracy of EPA's Air Pollution Control Cost Manual that is recommended by the BART Guideline.

In determining BART for NO_x at M.R. Young Station, the NDDH considered all five statutory factors. Our analysis of the costs indicate that both costs calculated by the NDDH and by Minnkota are excessive over the entire range of the costs estimated. In addition, the incremental cost effectiveness of SCR (LDSCR and TESCR) + ASOFA is excessive when compared to SNCR + ASOFA. Finally, the incremental amount of visibility improvement of SCR + ASOFA versus SNCR + ASOFA is negligible. Each of these factors (i.e. cost effectiveness, incremental cost or visibility improvement) by themselves would dictate that SCR + ASOFA is not BART.

The NDDH also considered the uncertainties regarding the technical feasibility of LDSCR and TESCR. Since Minnkota was unable to secure a vendor guarantee, the successful application of LDSCR and TESCR is more questionable.

Having considered the cost effectiveness, incremental cost, the incremental visibility improvement, and the uncertainties regarding the successful application of SCR to a source combusting ND lignite, the NDDH has determined that BART is not represented by SCR.

Comment 25: Appendix J.1, Consultation with Federal Land Managers: We note that in several of your responses to FLM comments, you cite to EPA's August 28, 2009 Advanced Notice of Proposed Rulemaking (ANPR) regarding the Four Corners Power Plant BART analysis. The ANPR does not represent an Agency decision but rather includes information on which EPA

Region 9 seeks comment. At this point, no Agency position has even been proposed, much less finalized. It is not appropriate to rely on the August 28, 2009 ANPR to support your position regarding BART analyses in North Dakota.

Response: The Department has reviewed the EPA Air Pollution Control Cost Manual which states "In practice, SCR systems operate at efficiencies in the range of 70% to 90%." EPA's Air Pollution Control Technology Fact sheet for selective catalytic reduction (EPA-452F-03-032) states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%." The Oregon DEQ hired Eastern Research Group, Inc. (ERG) to review the BART analysis for the PGE Boardman Plant. In their review, ERG stated "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR of the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The NDDH believes the use of 80% is a reasonable choice for a source that must meet a BART emission limit on a long-term continuous basis.

In addition to the ANPR estimate for SCR at the Four Corners Power Plant, the Department also reviewed the analysis commissioned by the Oregon DEQ for the cost of SCR at the PGE Boardman Plant. The analysis, which was prepared by Eastern Research Group, Inc. (ERG) states, "Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004. ERG analyzed the 2007 cost-basis data by eliminating the three highest and one project that was known to be very dissimilar to the Boardman Plant characteristics. The remaining nine projects range from $207/kw to $267/kw, with an average of $227/kw. ERG believes that this is a reasonable representation of 2007 costs of large SCR installations under normal retrofit conditions." This cost is two to three times the amount that would be estimated using EPA's Control Cost Manual. Further, these costs are for HDSCR. The cost for LDSCR and TESCR will be substantially higher because of the capital cost for the reheat system (including heat exchangers) and the operating cost for reheating the flue gas.

Comment 26: SO_2 and NO_x analyses: In general, analyses of control options and proposed limits should not be based on worst-case coal scenarios and/or highest calendar year emission rates. Use of averages should allow for accommodation of worst-case situations and will ensure that the more common conditions are adequately limited.

Response: The BART guidelines states "the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." Using worst-case emissions represents a realistic scenario because the scrubber will have to be designed for that coal and operation and maintenance costs will be higher with this higher sulfur coal. North Dakota lignite is extremely variable in both quality and sulfur content. Using an average sulfur content will not accommodate worst-case conditions. For Minnkota, one standard deviation of the sulfur content amounts to 0.53% sulfur or 57% of the average sulfur content. Prediction of future sulfur content has been based on a limited number of core samples. Using an annual average for the baseline eliminates some of this variability; however, it does not eliminate it all. The Department believes that a sulfur content at, or near, the maximum annual average provides a realistic depiction of emissions. This is the same as using the maximum two years of the last five or ten years to predict the baseline emission rate as suggested by EPA in the BART Guideline and in response to questions on BART (Question 7, August 3, 2006). The difference is that you have to look into the future to see what two years will provide the maximum emission rate.

For BART, EPA has indicated the limit must be on a 30-day rolling average. A 30-day rolling average emission rate is not equivalent to an annual average emission for North Dakota lignite which is highly variable. Our review of scrubber systems in North Dakota indicates as much as a one-third difference between these two emission rates. To account for this variability, the annual emission rate must be adjusted upward to get a 30-day rolling average. In addition, the Department has not allowed an exemption from the BART emission limits during startup/shutdown or malfunction (SSM). Therefore, SSM must be considered in setting the BART emission limit. Using a near maximum sulfur content allows the Department to set the BART limit without making an adjustment for SSM.

For NO_x, the average of the highest two years out of the last five years was used by the Department to establish a baseline. This is consistent with the BART Guideline (Section IV.D.4.d.1). It is also consistent with EPA's August 3, 2006, response to comments (Question 7) and consistent with BACT determinations.

Again, a 30-day rolling average NO_x emission rate is not equivalent to the annual average emission rate for boilers firing North Dakota lignite. Our analysis indicates the 30-day rolling average can be 15% or more higher than the annual average emission rate especially when SSM is considered.

Comment 27: NO_x analyses, Step 3: Evaluate Control Effectiveness of Remaining Control Technologies: Based on our comments #22-24 above and Enclosure 2, please ensure that inappropriate assumptions in the cost analyses for SCR were not carried over to the NDDH BART determinations for any of the facilities reviewed. In addition and as we have commented in previous correspondence, incremental cost analyses are intended to be a useful supplement, not a replacement, for standard $/ton calculations. It is not unusual that the incremental costs will be greater than the average cost effectiveness as the level of control increases, but this should not be an automatic basis for eliminating an option which has a reasonable average cost effectiveness.

Response: The Department believes that cost estimates are with ± 30% of the actual cost which is similar to the costs provided by EPA's Control Cost Manual (see Responses to Comments 22-24).

Incremental cost was considered in evaluating the various control options. As provided in the BART Guideline, "The greater the number of possible control options that exist, the more weight should be given to the incremental costs vs. average costs." The Department evaluated at least five different NO_x control options for each source subject to BART. As such, more weight was given to the incremental cost as recommended by the BART Guideline. The Department considered all five statutory factors in determining BART including average cost effectiveness and incremental cost.

<u>Comment 28</u>: The visibility impact analyses need to eliminate the reference to "3 units" for TRNP, as requested by the FLMs. We note that this change was made in the SIP text and should be carried over to these documents. TRNP was identified as a single national park under the Clean Air Act Amendments of 1977 (42 U.S.C. 7472); thus, there is only one mandatory Class I Federal area for this park. By dividing this Class I area into 3 units, there may be slight reductions in benefits predicted when modeling the visibility effects of applying controls.

<u>Response</u>**:** North Dakota has two Class I areas within its boundaries: the Theodore Roosevelt National Park which consists of three separate and distinct units and the Lostwood National Wildlife Refuge Wilderness Area. The Department considers the three units of Theodore Roosevelt National Park to be three separate areas for modeling purposes for the following reasons:

A. Theodore Roosevelt National Park (TRNP) as a PSD Class I area consists of three units (see 44 FR (November 30, 1979) at 69125 and 69127, 40 CFR § 81.423 and NDAC § 33-15-15-01.2 (Scope) relating to 40 CFR 52.21(e)). The areas are not contiguous. The North Unit and South Unit are separated by approximately 38 miles.

B. Federal regulation, 40 CFR 51.301, states "*Adverse impact on visibility* **means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent,** intensity, duration, frequency and time of visibility impairments and how these factors correlate with (1) times of visitor use of the Federal Class I areas, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas." (Emphasis added) Combining the three units of TRNP into a single area for visibility analysis fails to address the "geographic extent" of any visibility impairment.

C. The North Unit is not visible from the South Unit and vice versa. The commingling of receptors from the units for a visibility analysis misrepresents the ability of a park visitor to observe features in another unit.

Any viewable scenes outside any unit of TRNP from within the unit are "integral vistas". The effects on integral vistas are not considered when determining whether an adverse impact on visibility will occur. There are no geological features, terrain or structures in any unit of TRNP that are viewable from another unit across the land regions separating the units. For example, terrain peaks in the South Unit would have to rise at least 900 feet above terrain in the North Unit, due to the Earth's curvature, to be seen by a visitor in the North Unit. So the visual range of visitors in one unit does not include aspects of another unit.

D. The Department has treated the units as separate Class I areas for 30+ years for purposes of PSD increment consumption without objection from EPA or the FLMs prior to 2006.

E. Treating the three units as a single Class I area effectively extends Class I status to areas between the units which are classified as Class II by rule and law.

F. The units have three different names, the South Unit, the North Unit and the Elkhorn Ranch Unit.

Comment 29: Section II.A.2., Compliance Date: The last phrase "…approves this permit as part of the BART SIP" needs to be revised to "…approves this permit as part of the Regional Haze SIP."

Response: Agreed

Comment 30: Unit 1 SO_2 BART evaluation, p. 5: As we have commented in previous correspondence, we have concerns with the use of 35(s) as an alternative emission factor for SO_2. NDDH's response did not adequately justify the use of the alternative. The alternative factor was based on a study contained in NDDH's periodic review of PSD SO_2 increment consumption. In that study, an emission factor of 37.4(s) was proposed. For the Leland Olds BART determination, an emission factor of 35(s) was used to provide a conservative estimate of the uncontrolled emission rate. In the periodic review, NDDH apparently used CEM data from recent years to derive an alternative emission factor to estimate sulfur emissions. The EPA AP-42 emission factors were developed in the mid-1970s and include test data gathered at lignite burning power plants in North Dakota and elsewhere. EPA has concerns about using recent CEM data to adjust emission factors given that coal quality may have changed over the years, or may change in the future. However, in this instance it does not appear that the use of this alternative emission factor affects the results of the SO_2 BART determination.

Response: AP-42 makes several statements about the use of the emissions factors in the document. These include:

- Data from source-specific emission tests or continuous emission monitors are usually preferred for estimating a source's emissions because those data provide the best representation of the tested source's emissions.

- Use of these factors as source-specific permit limits and/or as emission regulation compliance determinations is not recommended by EPA. Because emission factors essentially represent an average of a range of emission rates, approximately half of the subject sources will have emission rates greater than the emission factor and the other half will have emission rates less than the factor. As such, a permit limit using an AP-42 emission factor would result in half of the sources being in noncompliance.

- Average emissions differ significantly from source to source and, therefore, emission factors frequently may not provide adequate estimates of the average emissions for a specific source. The extent of between-source variability that exists, even among similar individual sources, can be large depending on process, control system, and pollutant.

AP-42, in the Introduction-Figure 1, indicates that CEM data provides the best reliability for estimating emissions.

Based on the above, the Department believes an emission factor based on actual CEM data is far superior to the AP-42 emission factors. The baseline emissions that were estimated based on an emission factor derived from CEM data provides the most accurate data available. Using an inferior AP-42 emission factor would degrade the BART process. No changes were made based on this comment.

Comment 31: Units 1 and 2 NO_x BART evaluations:

(A) NDDH has revised its analysis and determines that LDSCR and TESCR are technically feasible and includes separate cost estimates for both systems. However, there is no explanation as to how the LDSCR cost values were obtained. Please clarify and include all supporting documentation in the SIP. See 40 CFR 51.308(e)(1).

(B) Based on our review of Basin Electric's May 29, 2009 supplemental TESCR cost analysis and NDDH's July 2009 SCR Technical Feasibility Analysis for North Dakota Lignite, we do not agree with certain assumptions used in the TESCR cost analysis. Please see Enclosure 2 for more detail, as well as our comments #22-23 above. Step 3 of the BART determination needs to be revised to address these concerns. These revisions are likely to considerably improve the cost effectiveness of TESCR for each unit, making it a reasonable selection for BART. In addition, this version of the draft BART determination includes new cost estimates for LDSCR. As explained above, it is unclear how the cost values for LDSCR were derived.

Response:

(A) The costs for LDSCR at Leland Olds were based on the cost estimate for M.R. Young 2 Station. The cost of TESCR was reduced proportionately to arrive at a cost for LDSCR. The smallest differential was used for the public comment period. The Department has revised the estimate based on the average of the "stand-alone" costs using M.R. Young 1 data for Leland Olds 1 and M.R. Young 2 data for Leland Olds 2. The detailed calculations are included in Appendix C.1.

(B) See our response to comments 22-23, we believe the cost estimate is within ±30% as would be estimated using the Control Cost Manual.

This comment seems to ignore the other four factors that are involved in making a BART determination, especially the amount of visibility improvement. Our cumulative modeling for Unit 2 shows only a 0.01 deciview improvement, in the most impaired days for SCR & ASOFA versus RRI & SNCR. The Department has the flexibility to weigh each factor as it chooses. The Department weighed visibility improvement fairly heavily in this analysis because the costs were very high. The Department has determined that the costs are excessive and the visibility improvement is so small that selection of SCR as BART is unwarranted.

<u>Comment 32</u>: Unit 1 NO_x BART evaluation, Step 3, p. 13: We note your reference to EPA's August 28, 2009 Advanced Notice of Proposed Rulemaking (ANPR) regarding the Four Corners Power Plant BART analysis to support the use of an 80% control efficiency for SCR with reheat. The ANPR does not represent an Agency decision but rather includes information for which Region 9 seeks comment. At this point, nothing has even been proposed much less finalized. It is not appropriate to rely on the ANPR to support your position regarding BART analyses in North Dakota. NDDH needs to explain why the more commonly accepted figure of 90% control efficiency is not warranted. For more information, please see the proposed and final Standards for Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units (70 FR 9713, February 29, 2005 and 71 FR 9869, February 27, 2006) and the May 2009 ICAC White Paper, pp. 4 and 7 (contained in Enclosure 3 of this letter).

<u>Response</u>: Although the ANPR was cited, that was not the only document that was relied on. The EPA Air Pollution Control Cost Manual states, "In practice, SCR systems operate at efficiencies in the range of 70% to 90%". EPA's Air Pollution Control Technology Fact Sheet for SCR (EPA-452F-03-032) states that SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%. The Arizona DEQ determined that SCR with LNB could achieve 75% reduction. The Oregon DEQ commissioned Eastern Research Group (ERG) to evaluate the BART analysis for the PGE Boardman Plant. In their Technical Memorandum #2 (copy attached), ERG states "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR at the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The Department stands by its decision to use 80% efficiency for SCR alone on a retrofit.

<u>Comment 33</u>: Unit 2 NO_x BART evaluation, pp. 23-31:

(A) Per the BART Guidelines, EPA has found that the use of SCRs at large cyclone units burning lignite enables the units to cost-effectively meet NO_x rates of 0.10 lbs/MMBtu. A revised cost analysis, using the necessary adjustments we have described in comment #23 and Enclosure 2, will most likely show that SCR is cost effective at this large boiler.

(B) For BART determinations, visibility improvement must be based on the 98th percentile day results, not the 20% worst days. We do not agree that single source modeling under the BART Guidelines overestimates visibility improvement. See comment #4 above for more detail. NDDH did not use this approach in the visibility analysis for Unit 1 and it must not be used for Unit 2.

(C) There appears to be a typographical error at the beginning of the last paragraph on p. 30 – should be "BART" instead of "BACT?"

Response:

(A) EPA did not evaluate the flue gas characteristics of North Dakota lignite when it established the presumptive BART NO_x levels for cyclone boilers. This is in direct opposition to the statements in the BART Guideline regarding technical feasibility of a control option (i.e. technical feasibility is based on an evaluation of the flue gas characteristics and the potential for successful application of the technology). Had EPA evaluated the flue gas characteristics of North Dakota lignite, they may have concluded that HDSCR is not technically feasible; however, no such EPA analysis is available. This failure of EPA will affect the estimated cost of achieving the presumptive levels. Had EPA conducted this analysis, the presumptive levels for cyclone boilers combusting North Dakota lignite may have been quite different.

(B) The Leland Olds Station is not subjected to the BART Guideline (i.e. <750 MWe). 40 CFR 51, Appendix Y states, "For sources other than 750 MW power plants, however, states retain the discretion to adopt approaches that differ from the guidelines". As demonstrated is the Response to Comment 4, single source modeling, as recommended in the BART Guideline, over predicts the amount of visibility improvement. The Department's cumulative modeling provides a more accurate estimate of the visibility improvement that is reasonably expected to occur and is more compliant with the requirements of Section 169A(g)(2) of the Clean Air Act than the BART single source modeling. We have exercised our discretion to use this approach for Unit 2 since the costs for SCR on a dollar per ton of NO_x removed and the incremental costs are very high.

(C) Agreed

Comment 34: The "References" section includes NDDH's 2005 Proposed Alternative Air Quality Modeling Protocol to examine the status of attainment of PSD Class I increments. This protocol was never approved by EPA, and contested elements of this protocol cannot be relied upon in your BART determinations.

Response: The reference only refers to emission factors that were calculated for the increment consumption analysis. These factors were not used in the BART analysis; a more conservative factor of 35(s) was used. As explained in the Response to Comment 30, we believe this factor provides a better estimate of sulfur dioxide emissions than the AP-42 factors because it more closely matches actual CEM data.

Comment 35: SO_2 evaluation, Step 2, 2nd paragraph, p. 8: There appears to be a typographical error in the 2nd to last sentence – should be Falkirk Mine instead of Center Mine?

Response: Agreed

Comment 36: SO_2 analyses, Step 5, p. 11: The reader is referred to the Great River Energy (GRE) BART Analysis, pp. 47-51, for visibility improvement analyses. While the 98th percentile results are provided in the GRE report, it is nearly impossible to understand the tables since results are combined for SO_2 and NO_x and there are no specifics provided for each scenario.

NDDH needs to extract the relevant 98th percentile results from the GRE analysis - by pollutant and by specific scenario – and incorporate them directly into the BART determination document. We note that this information has been added to the NO_x evaluation section but was still omitted from this SO_2 evaluation.

<u>Response</u>: Appendix Y to Part 51, Guidelines for BART Determinations Under the Regional Haze Rule states in part: "As long as these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section." In the case of Coal Creek SO_2, the most stringent control available was selected as BART and it will be made federally enforceable in the Permit to Construct. The amount of visibility improvement can be discerned from GRE's analysis.

<u>Comment 37</u>: NO_x analyses, Step 2: Eliminate Technically Infeasible Options, p. 15: As noted above in comment #22, we have provided substantial information and evidence that all SCR technology, including High Dust SCR, is technically feasible at facilities burning North Dakota lignite, and we continue to stand by those comments.

<u>Response</u>: The Department believes the preponderance of evidence indicates that HDSCR cannot be successfully operated when North Dakota lignite is combusted making this option technically infeasible.

<u>Comment 38</u>: NO_x analyses, Step 3: Evaluate Control Effectiveness of Remaining Control Technologies, pp. 15-16: NDDH needs to explain why it accepted GRE's suggested 80% control efficiency for LDSCR instead of using the generally accepted 90% efficiency. For more information, please see the proposed and final Standards for Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units (70 FR 9713, February 29, 2005 and 71 FR 9869, February 27, 2006) and the May 2009 ICAC White Paper, pp. 4 and 7 (contained in Enclosure 3 of this letter).

<u>Response</u>: See response to Comment 32.

<u>Comment 39</u>: NO_x analyses, Step 4: Evaluate Impacts and Document Results, p. 17:

(A) The elimination of SCR and SNCR based on uncertainty surrounding "potential" ammonia contamination of fly ash is not appropriate. The BART determination should be based on the 5-factor analysis, including any necessary data to address this question. GRE claims that installation of SCR or SNCR may negatively impact fly ash sales due to ammonia slip and may result in an ash disposal problem, but does not provide any manufacturer's data, vendor information, or other technical or commercial data to support its claims. See 40 CFR 51.308(e)(1). (SIP must include documentation for BART analyses.) It is our understanding that installation of SCR and SNCR result in very little, if any, impacts to fly ash sales since the ammonia slip for each control is now very low – less than 2 ppm for SCR and less than 5-10 ppm for SNCR. Given that this concern

> wasn't raised at the other BART sources where you have proposed SNCR, we know of no reason for it to apply to Coal Creek. We note that you cite to an example from Nebraska to support your decision. Please be advised that the cited example is from a draft BART determination analysis. The State of Nebraska has not submitted to EPA Region 7 its BART determination analysis as part of a final Regional Haze SIP. EPA Region 7 has not, and will not, make a determination regarding the approvability of Nebraska's BART determinations until it reviews all components of the final Nebraska Regional Haze SIP and acts on the revision through its own public notice and comment rulemaking.

Response: The commenter requested additional vendor information to support the determination that SCR and SNCR will result in ammonia slip and ash contamination that may reasonably be expected to negatively impact future ash sales. Additional information to support that conclusion is contained in a 2/9/10 GRE email that has been added to the supplemental information considered for the BART determination (copy attached to this response). This email contains recent testimonials from ash marketers, buyers and end product users that provide clear evidence of negative impact on ash sales and use when the ash is contaminated with ammonia by SCR and SNCR systems. The commenter statement that "It is our understanding that installation of SCR and SNCR result in very little, if any, impacts to fly ash sales"... is contradicted by these testimonials.

The commenter stated that EPA/R8 knows of no reason to apply the ash-ammonia contamination concern to Coal Creek since it was not a concern raised in NDDH BART determinations for other plants. The reason is simple: Coal Creek is the only North Dakota plant that has developed a market for ash, that has invested in the infrastructure to sell ash, and that is currently selling ash. It should be no surprise to anyone that companies do not raise the issue of lost sales for products that they do not market.

The commenter stated that NDDH could not use the Nebraska DEQ determination that SCR was not BART in part due to ash contamination by ammonia as supporting evidence because EPA has not yet approved the draft Nebraska Regional Haze SIP. It appears EPA fails to realize that evidence can be considered credible to NDDH even if EPA has not rendered an opinion on it. This evidence has weight with NDDH because the State of Nebraska has considered it and found it to be credible. Nebraska's BART determination analysis is proof that at least one other state has come to the same conclusion on this matter as NDDH.

Comment 40: Evaluate Visibility Impacts, Step 5, pp. 17-19: We note that you have extracted the visibility impacts data from the GRE BART analysis to include in the NO_x BART evaluation. However, it appears that you have presented the combined results for SO_2 and NO_x controls, not just the NO_x results. Please clarify.

Response: See response to Comment 36.

Comment 41: Summary, p. 23: Please correct typographical errors in the SO_2 BART limits for Unit 1 and Unit 2 – should be 95% instead of 94%.

Response: Agreed

Comment 42: II.A.4.a.: Please correct the typographical error in the first paragraph – should be 95% reduction limit instead of 94%.

Response: Agreed

Comment 43: Unit 1 and Unit 2 NO_x BART evaluation:

(A) In addition to objecting to selection of SNCR as BART based on the North Dakota record, we also object to your determination that separate NO_x limits are appropriate for startup. The record does not justify the need for such separate limits, nor does it justify that the selected values represent BART. As you know, the BART Guidelines contemplate pounds per million Btu limits that apply continuously, with a 30-day rolling average period to accommodate, among other things, potential short-term fluctuations in the emissions rate that may result during startups and other conditions.

As we have noted previously, separate startup limits have not been sought by, or provided to, other facilities (Leland Olds and Stanton) for which SNCR is proposed as BART, and we know of no reason M.R. Young warrants special treatment. NDDH alludes to the Consent Decree as a basis for special treatment and a need to harmonize the "BACT limits" under the Consent Decree and the BART limits. First, the Consent Decree terms with respect to startup were the result of a negotiated compromise in the context of an enforcement action. The Consent Decree terms are not binding in the context of this BART determination, and Paragraph 66 of the Consent Decree in no way settles whether separate startup BART limits are necessary or appropriate at M.R. Young. At this time, no BACT limit has been established at M.R. Young.

NDDH also alludes to the fact that SNCR, and perhaps the overfire air system, will not work optimally during startup. Of course, this is also true for the other facilities mentioned above. This fact alone is not convincing.

NDDH then references Minnkota's claim that startup has lasted up to 61 hours for Unit 1 and that noncompliance of this length will make compliance with the 30-day rolling average emission limit "extremely difficult." From your analysis, we cannot determine whether Minnkota was exercising good air pollution control practices to minimize emissions during this period or to minimize the duration of the startup, whether this length of startup was an anomaly, or what the average emissions rate was during this period. There is no mention of startups at Unit 2 or whether the same parameters can or should be applied. Also, we cannot determine from the analysis what the expected "normal" emissions rate is using SNCR and overfire air. Presumably, your proposed BART limits already include some margin of safety for operational variation.

Also, NDDH has not evaluated potential impacts of the separate startup limits on visibility or why the separate limits represent BART. We have found no indication that the proposed startup limits represent the most stringent level of control for those periods. Furthermore, there is virtually no explanation in your BART determination for the separate startup limit for Unit 2 or why it differs so greatly from the proposed startup limit for Unit 1, or why the other terms that apply to the startup limit for Unit 2 in the permit differ from those for Unit 1 or are warranted.

Even if we found the separate startup limits to be justified, we do not believe the permit is sufficiently clear with respect to determining compliance with the normal 30-day limits and the 24-hour startup limits. In calculating 30-day averages, how will days be accounted for that include some, but not all, hours of startup? How will startups that are less than 24 hours be accounted for in calculating 24-hour averages? Finally, we question the use of heat input levels to define the end of startup as opposed to using temperatures. The latter would be more directly related to SNCR performance.

(B) As we have commented in previous correspondence, the presumptive limits should apply as the control floor since the total generating capacity is actually greater than the reported nameplate capacity of 734 MW, in fact, > 750 MW. In a November 20, 1995 letter, Minnkota advised NDDH that M.R. Young was operating at levels above nameplate and requested a change in the permit description of each unit to 277 MW for Unit 1 and 517 MW for Unit 2. These changes reflected the capabilities of the units as they "are currently with respect to generator output" and result in a total generating capacity of at least 794 MW. Per the BART Guidelines, EPA has found that the use of SCRs at cyclone units burning lignite should enable these large units to cost-effectively meet NO_x emission rates of 0.10 lbs/MMBtu.

(C) We assume that NDDH has revised its cost estimates based on Minnkota's November 2009 Supplemental NO_x BACT Analysis Reports for Units 1 & 2. Minnkota's revised cost analyses are unsubstantiated and highly questionable in many regards, as discussed in comment #24 above. Based on our review of Minnkota's supplemental reports and this BART determination, the NO_x BART determinations need to be revised to address these issues. Revisions, per our comments, are likely to considerably improve the cost effectiveness of SCR for each unit, making it a reasonable selection for BART. In addition, we have the following concerns specific to the BART determination document:

(1) NDDH has assumed a control efficiency of 90% (combined) for ASOFA with SCR. EPA expects that NO_x emissions can be reduced by 90% with SCR alone. Please see the proposed and final Standards for Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units (70 FR 9713, February 29, 2005 and 71 FR 9869, February 27, 2006) and the May 2009 ICAC White Paper, pp. 4 and 7 (contained in Enclosure 3 of this letter). Minnkota's own cost analysis uses 93.8% combined control and 90% control beyond ASOFA with SCR. The BART determination simply states that NDDH believes a reduction of 90% for ASOFA and SCR is "more appropriate on a long-term basis" without providing any rationale. Using a lower control efficiency results in significantly inflated $/ton values.

(2) The footnote on the cost tables (p. 14 and p. 29) indicates that the cost range provided is based on the difference in applying SCR to each unit as a stand alone retrofit (high end cost) and applying SCR to both Units 1 & 2 with shared facilities (low end cost). Minnkota provided these scenarios in its cost analysis. However, it appears the difference between the low and high end of the annualized cost range in NDDH's BART determination is based on "Scenarios A & B" in Minnkota's cost analysis. Scenario A (the lower cost) assumes a catalyst layer replacement (and unit outage time) every 16,000 hours, while Scenario B (the higher cost) assumes a catalyst layer replacement (and additional unit outage time) at each scheduled boiler cleaning outage. For Unit 1, this is three times a year and for Unit 2 this is four times per year. EPA believes that Scenario B is not realistic for a LDSCR or TESCR and should be completely disregarded. It appears as though NDDH is in agreement, but inadvertently used the Scenario B values for the high end of the cost range, rather than using the stand-alone values. In addition to mistakenly using the Scenario B values from Minnkota's cost analysis, it appears that NDDH used the Scenario A & B costs from the "shared facility" Table 4-7SF for Unit 1, while using the Scenario A & B costs from the "stand alone" Table 4-7SA for Unit 2. Correcting these values significantly reduces the higher annualized cost estimate (based on a stand alone unit instead of Scenario B) leading to a much smaller range between the low-end and high end estimates. The lower cost estimate (representing shared costs between Unit 1 and Unit 2 for Scenario A) and the higher cost estimate (representing Scenario A stand alone unit) should be as follows:

Unit 1 LDSCR: $31,749,000/$36,872,000
Unit 1 TESCR: $39,307,000/$44,465,000
Unit 2 LDSCR: $57,351,000/$59,881,000
Unit 2 TESCR: $66,506,000/$69,057,000

(3) Combining the higher 93.8% control efficiency for SCR + ASOFA (as submitted by Minnkota) and the worst case scenario cost described by NDDH in the BART Determination (stand alone unit costs, Scenario A), the following represents the <u>high-end</u> costs for Units 1 & 2:

Scenario A Stand Alone Costs:	Annual NOx Tons Removed	Levelized Total Cost ($1000)	Average Control Cost ($/ton)
Unit 1 (LDSCR)	9,348	36,872	3,944
Unit 1 (TESCR)	9,345	44,465	4,758
Unit 2 (LDSCR)	14,862	59,881	4,029
Unit 2 (TESCR)	14,857	69,057	4,648

On p. 17 of the BART Determination for Unit 1, NDDH “considers the cost effectiveness and incremental cost of SCR + ASOFA at the low end of the cost range to be reasonable,” while the higher end of the range was considered excessive. However, NDDH made this determination based on an error in the calculation of the high-end cost ranges (based on the Scenario B assumption that catalyst is replaced every time the unit is down for a planned outage). NDDH's low-end cost effectiveness values ($/ton) range from $3906/ton to $4948/ton. Given that the corrected high-end cost estimates are not dissimilar from NDDH's reasonable low-end estimates, these high-end costs should be considered reasonable at present.

As described earlier (and apparently supported by NDDH's narrative in the BART Determination, as well as NDDH's criteria for technical feasibility, *i.e.*, a catalyst replacement schedule of 3-4 times per year would not have been considered technically feasible by NDDH), Scenario B should be dismissed. When the high-end cost range becomes the intended "Stand Alone" facility costs, and more appropriate NO_x removal efficiencies are assumed (as provided by Minnkota), the high-end costs become very similar to (and in some cases lower than) what the NDDH BART Determination calculated as low-end costs deemed to be reasonable. There is little difference in these high-end cost effectiveness values for Units 1 and 2. As such, EPA concludes that even without examining the concerns and problems with Minnkota's initial cost values, as discussed in comment #24 above, the existing information for the BART Determination demonstrates that SCR is cost effective. Once appropriate adjustments are made to reflect more realistic costs, these values will become even more reasonable.

(D) As noted above in comment #4, BART visibility improvement analyses must be based on the 98th percentile day results, not the 20% worst days. We do not agree that modeling based on the BART Guidelines overpredicts the visibility improvement in North Dakota.

Response:

(A) The BART Guideline, Section IV.C states "unless there are new technologies which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for purposes of BART. We believe that the same rationale holds true for emissions standards developed for municipal waste incinerators under CAA Section 111(d), and for many NSR/PSD determinations and **NSR/PSD settlement** agreements." [emphasis added]. Clearly, the terms of Consent Decrees, such as the one with Minnkota, can be used in determining BART limits including startup limits that are separate from normal operation limits.

Minnkota did not include emissions from startups in their proposed BART limit because the Consent Decree indicates they must be addressed separately. Other sources have included these emissions in their proposed BART limit. Leland Olds Unit 2 has a baseline emission rate of 0.67 lb/10^6 Btu with a BART limit of 0.35 lb/10^6 Btu. The Minnkota Unit 1 baseline is 0.85 lb/10^6 Btu while Unit 2 is 0.79 lb/10^6 Btu. We have proposed a BART limit for Unit 1 of 0.36 lb/10^6 Btu and 0.35 for unit 2 (same as Leland Olds Unit 2). It is obvious that the Leland Olds Unit 2 limit has startups included in the rate.

The maximum 24-hour NO_x emission rates for M.R. Young that were used to determine BART applicability were 2,855 lb/hr and 5,364 lb/hr for Units 1 and Unit 2, respectively.

These values excluded startup, shutdown and malfunctions. The proposed startup limits are 2,070 lb/hr and 3,996 lb/hr for Unit 2 (24-hr average). This represents a 25-30% reduction from the baseline emission rate based on the proposed BART limits for startup. This clearly indicates there will be an improvement in visibility in the Class I areas even under the startup limits. When comparing the proposed startup limits to normal baseline emissions, it is evident that Minnkota will have to take steps to minimize emissions. Startup emissions can exceed 1 lb/10^6 Btu. The proposed startup limits represent 0.83 lb/10^6 Btu that must be averaged over the startup period. This is considerably less than the baseline emission rates (excluding SSM) which are 1.14 and 1.12 lb/10^6 Btu based on the heat input at the end of the startup period. Minnkota's justification is in Sections 3.5.2 of their analysis for each unit. The justification is virtually the same for each unit. The Department saw no reason to repeat its analysis for the similar units in its BART determination.

The Department will be making a BACT determination for the units for NO_x. That BACT determination will include startup limits. If the BACT limits are more stringent than the BART limits, the Department will reopen the Regional Haze SIP and incorporate the more stringent limits into the BART Permit to Construct.

The startup limit for Unit 2 is much higher than Unit 1 since it is a much larger unit (i.e. 477 MWe versus 257 MWe). However, the average lb/10^6 Btu emission rate during the startup is the same (0.83 lb/10^6 Btu) for both units.

Compliance with the NO_x BART limit will be determined based on the average of all hours in the 30 successive boiler operating dates except that only startups will be excluded from the 30-day rolling average. Malfunctions and shutdowns will be included. Any hours of startup will be excluded from calculating the 30-day rolling average emission rate. For startups that equal or exceed 24 hours, the average emission rate is calculated as the arithmetic average of 24 consecutive hourly emission rates. For startups that are less than 24 hours, compliance will be determined based on the arithmetic average for the duration of the startup period. The Permit to Construct has been modified to include this compliance determination method.

(B) The November 20, 1995 letter lists an URGE rating which is a three hour test. This rating does not represent a long-term rating or one that can be sustained more than three hours. The Acid Rain database lists M.R. Young Station as having a capacity of 734 MWe. The Energy Information Administration of the Department of Energy lists M.R. Young as having a summer time capacity of 697 MWe. Although Section 169A(b)(2) of the Clean Air Act does not define "total generating capacity", Section 169A(c) does discuss exempting power plants from the BART requirements if the total design capacity is less than 750 megawatts and it does not significantly contribute to visibility impairment. "Total design capacity" is equal to or less than the nameplate rating of the generators. In addition, the presumptive BART limits for NO_x were based on the nameplate capacity of the sources (see Technical Support Document; Methodology for Developing BART NO_x Presumptive Limits). Therefore, we believe M.R. Young Station is not subject to the BART Guidelines or the presumptive BART limits.

(C)(1) See response to Comment 25.

The 80% removal efficiency expected for SCR is in the middle of the range of efficiencies indicated in two EPA documents (see response to Comment 25) and ERG's analysis for the PGE Boardman Plant (see response to Comment 25). The BART Guideline in Step 4 states "The value selected for the design parameter should ensure that the control option will achieve the level of emission control being evaluated." The NDDH is confident that SCR + ASOFA will achieve 90% control; however, the amount of time an SCR will achieve this level of control (i.e. catalyst life) is unknown. Whether SCR will achieve 93.8% reduction efficiency over an extended period of time at M.R. Young is debatable.

The NDDH has included Minnkota's cost effectiveness and incremental cost results in our BART determination analysis. These calculations are based on 93.8% reduction efficiency. The NDDH considers the cost effectiveness and incremental costs calculated by Minnkota to be excessive over the entire range of costs.

(C)(2) The costs that are now shown represented the full range of costs provided by Minnkota. The footnote at the bottom of the cost tables has been changed to indicate that the entire cost range is provided. The NDDH has included all scenarios to show that the cost effectiveness and incremental cost is excessive regardless of the catalyst changeout schedule or whether cost should be calculated based on standalone facilities or shared facilities. Based on both the NDDH's and Minnkota's estimate cost effectiveness and incremental cost, the cost of SCR is considered excessive.

(C)(3) The cost estimate in the FLM review version of the BART determination analysis was updated by using Minnkota's cost estimate instead of one based on the cost estimate for Leland Olds Unit 2 which indicated lower costs. However, some of the discussion on cost effectiveness for M.R. Young Unit 1 from the FLM review version was not updated. This error has been corrected and EPA should not draw any conclusions regarding cost effectiveness or incremental cost effectiveness from this erroneous text.

The NDDH has included Minnkota's calculation of cost effectiveness and incremental cost in its BART determination analysis. These costs are based on 93.8% reduction efficiency. The cost effectiveness and incremental cost effectiveness are considered excessive over the entire range of costs.

Minnkota has been unable to obtain a vendor guarantee for the catalyst for either LDSCR or TESCR. This indicates that no one can predict with any reasonable accuracy the life of the catalyst. Therefore, the costs over the entire range were considered and found to be excessive.

The Department considered all five factors in determining BART for the M.R. Young Station. The incremental improvement in visibility of SCR + ASOFA versus SNCR + ASOFA is negligible (0.01 deciviews at TRNP and LWA for Unit 1 and 0.01 and 0.02 deciviews respectively at TRNP and LWA for Unit 2). This incremental improvement in visibility would cost at least $2,605,400,000 per deciview at Unit 1 and at least $2,286,700,000 per deciview for Unit 2 based on the cumulative modeling. The NDDH considers this amount of visibility improvement to be negligible and the cost unreasonable.

Even using 93.8% removal efficiency will not create much additional visibility improvement (approximately 4% additional reduction of emissions). Modeling by the NDDH indicates that SCR + ASOFA operating at 93.8% efficiency will only improve visibility 0.001 deciviews in the most impaired days when compared to SCR + ASOFA operating at 90% efficiency. The incremental visibility improvement between SCR + AOFA and SNCR + ASOFA would still be negligible.

As part of the BART process, the NDDH had to determine if LDSCR and TESCR were technically feasible. When this determination was made, the NDDH had information that a vendor guarantee could be secured for TESCR at M.R. Young Station. More recent information provided by Minnkota indicates this is not true. The uncertainty whether LDSCR or TESCR can be successfully applied at M.R. Young was weighed in the decision not to require LDSCR or TESCR. The BART Guideline states "there may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology." Requiring the use of SCR that cannot be successfully applied at M.R. Young Station would have severe economic effects on Minnkota Power Coop.

The NDDH considers the cost effectiveness of SCR + ASOFA to be excessive. The NDDH considers the incremental cost of SCR + ASOFA versus SNCR to be excessive. This determination is applicable to both the NDDH's calculated cost values and Minnkota's values and is applicable to the entire range of costs. The NDDH considers the amount of visibility improvement of SCR + ASOFA versus SNCR + ASOFA to be negligible. The NDDH also considered the uncertainties of the technical feasibility of LDSCR and TESCR to M.R. Young Station Units 1 and 2 which is highlighted by the lack of a vendor guarantee. The NDDH stands by its determination that SCR + ASOFA is not BART.

(D) See response to Comment 4.

Comment 44: Unit 2 SO_2 Evaluation, Step 3, p. 21: We note the baseline SO_2 emissions have been revised from 16,728 tons/year upward to 18,090 tons/year in this draft. Please explain why this revision was necessary at this late date.

Response: The baseline was revised to match the expected average sulfur content for future coal. The previous baseline was based on historical data which represented coal with a lower sulfur content. The change was made in response to an FLM comment. The Department believes the use of future coal sulfur content is more consistent with the discussion on baseline emissions in the BART Guideline since it represents anticipated emissions from the unit. It did not affect the BART decision since the most efficient control option was selected both in the public comment version and the final version.

<u>Comment 45</u>: II.A.1.c., NO_x limits: The alternative limits for startup are not acceptable. See comment #43(A) above.

<u>Response</u>: See response to Comment 43.

<u>Comment 46</u>: II.A.1.e.: The condition that SO_2 and PM limits apply at all times, including startup, shutdown, emergency and malfunction should also apply to NO_x limits.

<u>Response</u>: Minnkota did not request a different limit for SO_2 or PM during startup. Therefore, we did not consider it.

<u>Comment 47</u>: II.A.4.b.(8): This language regarding averaging the emissions of Unit 1 and Unit 2 is not consistent with the language in the BART determination document, Section IX. The BART determination includes a formula and definition for Average Allowable Emission Rate (AER), which is not included in the permit. Please clarify.

<u>Response</u>: The formula for Average Allowable Emission Rate (AER) is unnecessary since averaging is only allowed if Unit 2 is basing compliance on percent reduction. Since both Unit 1 and Unit 2 have an AER of 95% reduction, the Average Allowable Emission Rate is 95%; no calculation is needed. This is specified in Condition IX.A.3(a).

<u>Comment 48</u>: SO_2 BART evaluation in general: NDDH notes that a circulating dry scrubber was eliminated from consideration due to excessive incremental costs. However, EPA would not find the cost effectiveness of this option ($1631/ton) unreasonable compared with other BART determinations reviewed.

<u>Response</u>: EPA states that the cost effectiveness of a circulating dry scrubber ($1,631/ton) is not unreasonable. However, as EPA is aware, the Department eliminated a circulating dry scrubber from consideration as BART based upon the high incremental cost of greater than $10,600/ton. It is the Department's position that both cost effectiveness and incremental cost must be considered in the analysis in accordance with long-standing EPA policy. The New Source Review Workshop Manual states, "This type of analysis should demonstrate that a technically and economically feasible control option is nevertheless, by virtue of the magnitude of its associated costs and limited application, unreasonable or otherwise not "achievable" as BACT in the particular case. Average and incremental cost effectiveness numbers are factored into this type of analysis." It is our understanding that EPA's policy (i.e., that both cost effectiveness and incremental cost should be considered) remains as stated in the Manual. The Department considered both cost effectiveness and incremental cost in accordance with long-standing EPA policy and determined that the incremental cost is excessive for a circulating dry scrubber. The Department maintains the position that the incremental cost of a circulating dry scrubber is excessive and this excessive incremental cost is a sufficient reason to eliminate a circulating dry scrubber from consideration.

<u>Comment 49</u>: SO_2 BART evaluations for lignite and PRB coal, pp. 8 and 22: In an effort to assess the coal quality basis for NDDH's proposed SO_2 BART determinations for Stanton, we conducted an independent analysis, using lignite and PRB coal data contained in EPA's Clean Air Markets Division (CAMD) database. The 30-day average SO_2 emission potentials (in lb/MMBtu and percent sulfur) of lignite and PRB coal are available for a wide variety of sources through CAMD, and for most (if not all) of the large coal mines in the region. We would be happy to share this information with NDDH, if desired. Since these data are readily available, we see no need for the use of a 33% multiplication factor to adjust an annual average emission rate to a 30-day rolling average emission rate.

Based upon our review of the lignite coal quality data in the CAMD database for 2007-2009, it appears that NDDH's proposed SO_2 BART limit of 0.24 lb/MMBtu when burning lignite is in the range of what we'd expect to see at a 90% control efficiency. However, we wish to note that if NDDH believes that the proposed Spray Dryer Absorber and Fabric Filter will be able to achieve 90% reduction of SO_2 emissions while burning low sulfur PRB coal, the control devices should be able to achieve greater than 90% control when burning higher sulfur content lignite coal.

Based on our review of the PRB coal quality data in the CAMD database for 2007-2009, NDDH's proposed SO_2 BART limit of 0.16 lb/MMBtu when burning PRB coal appears to be too high. The NDDH based its proposed limit on an estimate of 1.2 lb/MMBtu for the annual average SO_2 emission potential of PRB coal, then applied 90% control efficiency to yield 0.12 lb/MMBtu controlled SO_2 on an annual average, then multiplied by 1.33 to convert to a 30-day average limit of 0.16 lb/MMBtu. The NDDH's estimate of 1.2 lb/MMBtu emission potential for PRB coal was apparently based on coal sulfur content of about 0.64%. The NDDH's BART Determination document does not indicate which mines were averaged together to yield 0.64%. Data we obtained from CAMD's database for 15 of the largest PRB coal mines reveal that PRB coal typically has much lower sulfur content on a 30-day average, about half of the 0.64% used by NDDH. Our analysis of that data yielded an average SO_2 emission potential of 0.78 lb/MMBtu, on a 30-day basis, for all of the PRB coal mines together.

It appears that NDDH wishes to use the high end of a 95% confidence interval rather than an average value to set the 90% reduction limit. Therefore, we have averaged all the high end values of all the 95% confidence intervals for all the PRB mines for which we obtained data. The average of these 95% confidence intervals is 0.95 lb/MMBtu, again on a 30-day average basis. The resulting SO_2 BART limit when burning PRB coal at a 90% control efficiency would most likely be in the vicinity of 0.095 lb/MMBtu, on a 30-day rolling average.

Response: EPA states, "we see no need for the use of a 33% multiplication factor to adjust an annual average emission rate to a 30-day rolling average emission rate." The EPA provides no data to support this position and only refers to an "independent analysis" conducted by EPA. As EPA is well aware, a party (including EPA) wishing to comment during a comment period is under an obligation to submit any data that the party wishes the Department to consider. Since EPA failed to submit any data during the comment period, the Department is unable to conduct a review of EPA's data. It should be noted that EPA has been aware of the use of the 33% adjustment factor at least since August 4, 2008, did not comment on the use of the factor in EPA's October 23, 2009 comment letter and only now comments on the use of the factor. In a response to a direct request from EPA Region 8 for more information regarding the use of the 33% adjustment factor, the Department sent a December 2, 2009 email to EPA Region 8 showing that the adjustment factor is based upon actual operating data at two North Dakota facilities. EPA did not ask for further data regarding the use of the 33% factor and apparently chose instead to move directly to an "independent analysis." Given that EPA failed to submit this "independent analysis", the Department cannot determine if EPA even considered the Department's data as part of the analysis.

It is common practice to establish higher short-term limits to allow for short-term emissions variability inherent to facility operations. The EPA RACT/BACT/LAER Clearinghouse contains numerous examples of short-term BACT limits which are higher than longer-term BACT limits. For example, a permit issued to Omaha Public Power District (RBLC ID NE-0031) on March 9, 2005 establishes a 3-hour average SO_2 BACT emission limit of 0.48 lb/MM Btu compared to the 24-hour SO_2 BACT limit of 0.163 lb/MM Btu and a 30-day rolling average SO_2 BACT limit of 0.095 lb/MM Btu. A permit issued to Wellington Development / Greene Energy (RBLC ID PA-0248) on July 8, 2005 establishes a 3-hour average SO_2 BACT limit of 0.234 lb/MM Btu and a 30-day rolling average SO_2 BACT limit of 0.156 lb/MM Btu. A permit issued to River Hill Power Company (RBLC ID PA-0249) on July 21, 2005 establishes a 24-hour average SO_2 BACT limit of 0.274 lb/MM Btu and a 30-day rolling average SO_2 BACT limit of 0.20 lb/MM Btu. Two examples where annual and 30-day rolling average BACT limits were established include permits issued to Associated Electric Cooperative (RBLC ID MO-0077) and Western Farmers Electric Cooperative (RBLC ID OK-0118). The permit issued on February 22, 2008 to Associated Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.065 lb/MM Btu and an annual average NO_x limit of 0.05 lb/MM Btu. The permit issued on February 9, 2007 to Western Farmers Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.07 lb/MM Btu and an annual average NO_x limit of 0.05 lb/MM Btu. In addition, a permit issued by EPA on July 31, 2008 for the Desert Rock facility establishes a 30-day rolling average NO_x limit of 0.05 lb/MM Btu and an annual average NO_x limit of 0.0385 lb/MM Btu. Clearly, it is common practice to establish short-term BACT limits which are higher than longer-term BACT limits.

The Department has reliable data based upon actual facilities operating in North Dakota to support the use of the 33% adjustment factor. In addition, adjustment factors (to adjust from an annual average limit to a 30-day rolling average limit) calculated from Associated Electric Cooperative, Western Farmers Electric Cooperative and Desert Rock limits are approximately 30%, 40% and 30%, respectively. These adjustment factors are very close to the adjustment factor of 33% used by the Department. Since the Department has reliable data to support the use of the 33% adjustment factor and no data has been submitted indicating that the factor is not appropriate, the Department maintains the position that the 33% adjustment factor is appropriate.

EPA states that "the control devices should be able to achieve greater than 90% control when burning higher sulfur lignite coal"; however, EPA provides no data to support this statement. The Department is aware that higher control efficiencies are thought to be attained when high sulfur coal is burned; however, EPA provides no data indicating that a higher control efficiency can be attained when burning lignite (with an assumed uncontrolled SO_2 emission rate of approximately 1.8 lb/MM Btu) as compared to PRB (with an assumed uncontrolled SO_2 emission rate of approximately 1.2 lb/MM Btu). Given that some facilities in the U.S. burn coal which results in uncontrolled SO_2 emission rates in excess of 4 lb/MM Btu, neither lignite nor PRB would be considered to be a “high sulfur coal” in comparison. Based on the available data, the Department maintains the position that a SD/FF at Stanton Station #1 is capable of an average sulfur dioxide control efficiency of 90%.

EPA states that “Data we obtained from CAMD’s database for 15 of the largest PRB coal mines reveal that PRB coal typically has much lower sulfur content on a 30-day average, about half of the 0.64% used by NDDH. Our analysis of that data yielded an average SO_2 emission potential of 0.78 lb/MMBtu, on a 30-day basis, for all of the PRB coal mines together.” The EPA submits no actual data and just refers to “data we obtained…for 15 of the largest PRB coal mines…”. EPA does not indicate which coal mines were studied and why certain mines were apparently not included in the study. EPA is under an obligation to submit any applicable data that EPA wishes the Department to consider. Unfortunately, since EPA failed to submit any data during the comment period, the Department is unable to conduct a review of EPA’s data. However, the Department did consult the U.S. Geological Survey (USGS) Coal Quality Database (available at www.usgs.gov) and found that the database currently includes over 700 samples of Wyoming and Montana subbituminous for which sulfur was analyzed. The Department has analyzed this data and has determined that the average sulfur content based on all of the samples is approximately 0.83%. In addition, the GRE BART submittal includes actual data from three mines from which GRE could potentially receive coal. The average coal sulfur contents for the three mines are 0.34%, 0.64% and 0.80%, for an average sulfur content of approximately 0.59% (on a heat input basis, the average uncontrolled SO_2 emission rate is calculated to be approximately 1.17 lb/MM Btu compared to the SO_2 emission rate assumed in the analysis of 1.2 lb/MM Btu). Based upon the available data the Department maintains the position that the uncontrolled SO_2 emission rate of 1.2 lb/MM Btu used to calculate emissions when burning PRB coal is reasonable.

Comment 50: NO_x BART evaluation: As we have commented in previous correspondence, the 45% control efficiency assumed for the alternative of combining combustion controls plus SNCR is lower than we’ve seen elsewhere. Please explain why NDDH accepted this control efficiency number from GRE. In addition, as noted above in comment #22, we have provided substantial information and evidence that all SCR technology, including High Dust SCR, is technically feasible at facilities burning North Dakota lignite.

Response: EPA states that the 45% control efficiency assumed for the alternative of combining combustion controls plus SNCR “is lower than we’ve seen elsewhere” and asks the Department to “explain why NDDH accepted this control efficiency from GRE.” EPA provides no data to support the EPA’s contention that the control efficiency “is lower than we’ve seen elsewhere.”

In the response to public comments for the Desert Rock Energy Facility dated July 31, 2008, EPA states, “A BACT determination involves judgment and balancing, and does not involve simply picking the lowest numerical emission limit or the highest observed control efficiency. The design of a wet FGD system and the resulting control efficiency depends on a variety of parameters, including the characteristics of the fuel, boiler operating data and tolerances, emission requirements…, limestone availability and quality, and economic factors.” In the Desert Rock case, EPA clearly recognizes that a number of factors must be taken into account when determining if a control efficiency is acceptable. However, in the above comment the EPA appears to ask the Department to increase an assumed control efficiency based on no data and only a vague, unverifiable statement from EPA regarding what EPA has "seen elsewhere." EPA does not even discuss if the control efficiencies EPA has "seen elsewhere" are for sources that are comparable to Stanton Station #1.

In a technical memorandum dated June 26, 2008 prepared by Eastern Research Group, Inc. (ERG) regarding the estimation of costs and impacts of NO_x control technologies applied to the PGE Boardman Plant (a coal-fired facility), ERG conservatively estimates an 18 percent SNCR control efficiency for the PGE Boardman Plant. The same memorandum references an estimate by Black and Veatch of a 20 to 25 percent SNCR control efficiency. The memorandum also states, "With regard to SNCR performance, although SNCR installations on boilers have been demonstrated to achieve between 25 and 50 percent reduction in NO_x, very large boilers (>300 MW) generally are limited to lower SNCR removal efficiencies."

The EPA Air Pollution Control Cost Manual states, "SNCR can achieve NO_x reduction efficiencies of up to 75 percent (%) in selected short-term demonstrations. In typical field applications, however, it provides 30% to 50% NO_x reduction." A table in the Manual labeled "SNCR NO_x Reduction Efficiency for Various Boiler Sizes" indicates that the SNCR reduction efficiency for the size of a boiler at Stanton Station #1 (1,800 MM Btu/hr) would be expected to be less than 40%.

GRE has described the rationale for the control efficiency selected and the EPA has not identified any actual concerns with GRE's rationale, has not provided any actual data relating to SNCR control efficiencies at Stanton Station #1 and can only offer a vague, unverified statement regarding SNCR control efficiencies. The available data indicates that a 45% control efficiency is reasonable and may in fact be on the higher end of achievable control efficiencies for SNCR applied to a coal-fired unit of the size at Stanton Station #1 as a retrofit. Given that the available data clearly indicates that the assumed 45% control efficiency is reasonable and EPA has offered no data to the contrary, the Department maintains the position that the 45% control efficiency is reasonable.

Comment 51: II.A.3., Continuous Emission Monitoring (CEM): Based on GRE's comments, this section of the permit was revised to eliminate the phrase "Main Stack" from "Unit 1 (Main Stack)" as the location for the CEM. For clarity, the permit needs to be revised to specify that the CEM location for a particular pollutant is downstream of controls for that pollutant (unless control efficiency is being measured by a combination of upstream and downstream CEMs, in which case one of the CEMs for that pollutant would be upstream of controls).

Response: The Department believes is inherently obvious that the pollutant concentration will be measured downstream of the control equipment since the CEM is meant to establish compliance with the emission limits. However, to address EPA's concern, the Department has added language to clarify that the CEMs must be located downstream of the control equipment.

Comment 52: Based on your discussions with Otter Tail Power Company, it appears that this level of minimal control is considered reasonable at this time. Therefore, even if you disagree with our other comments regarding Reasonable Progress, at least this level of NO_x control should be included in the SIP as a required Reasonable Progress control measure. As such, the permit should more closely mirror the BART permit format, including the appropriate 30-day rolling average emission limit, compliance date no later than 2018 (or sooner if reasonable), and compliance determination, monitoring, recordkeeping, and reporting requirements.

Response: The Department has found through its reasonable progress analysis that additional controls on Coyote are not reasonable. Nevertheless, in an effort to demonstrate that North Dakota continues to work with companies to make further reductions, NO_x reductions at the Coyote Station are being included in the SIP. We have relocated the write-up on the Coyote Station to Section 10.6.1, Emission Reductions Due to Ongoing Air Pollution Control Programs. Since this source is not subject to BART, we believe the Permit to Construct is appropriate. The equipment will be installed by July 1, 2018.

Comment 53: II.A.2, Compliance Date: There appears to be a typographical error in the heading – should be "Date" instead of "Data."

Response: Agreed

Attachments

1. ERG Technical Memorandum on PGE Boardman Plant.

2. October 6, 2008 email from Steve Weber to Kevin Golden.

3. Minnkota response to questions on SCR Cost Estimate; February 11, 2010.

4. GRE Response on Ammonia in Flyash; February 9, 210.

Technical Memorandum #2

To: David Collier, Oregon Department of Environmental Quality
Brian Finneran, Oregon Department of Environmental Quality
Mark Fisher, Oregon Department of Environmental Quality

From: Roger Christman, Roy Oommen, and Paula Fields

Subject: Estimation of Costs and Impacts of NO_x Control Technologies Applied to the PGE Boardman Plant

Date: June 26, 2008

INTRODUCTION

In response to the U.S. EPA final rule on Regional Haze and Best Available Retrofit Technology (BART) determinations, and at the request of the Oregon Department of Environmental Quality (DEQ), Portland General Electric Company (PGE) submitted their proposed BART analysis for the Boardman Plant (PGE Proposal) on November 5, 2007. The PGE proposal was prepared by Black & Veatch (B&V) and CH2M Hill.

In December 2007, Eastern Research Group, Inc. (ERG) was engaged by the DEQ to assist in the evaluation of the PGE Proposal and to conduct an independent feasibility assessment of select options for control of nitrogen oxides (NO_x) from the coal-fired Boardman Plant. ERG's scope of work (SOW), as contained in Contract 055-08, includes the following tasks:

- Task 1: Participate in a kick-off meeting in Portland with PGE, DEQ, and key stakeholder groups
- Task 2: Participate in a site visit to the Boardman Plant
- Task 3: Submit a trip report documenting the results of Tasks 1 and 2
- Task 4: Evaluate the PGE Proposal and submit memo of findings (Memo #1)
- Tasks 5 and 6: Evaluate NO_x control technologies (i.e., low NO_x burners with overfire air and selective noncatalytic reduction, low NO_x burners with overfire air and selective catalytic reduction, and other control options as identified by DEQ), and submit a memo of findings (Memo #2)
- Task 7: Participate in a meeting to discuss findings of Memos #1 and #2 with DEQ, PGE, and other stakeholder groups
- Tasks 8, 9, and 10: Prepare outline of draft report, submit draft report, and meet with DEQ, PGE, and stakeholder groups to discuss draft report
- Task 11: Participate in meeting with DEQ's BART rulemaking Advisory Committee
- Task 12: Submit final report
- Task 13: Provide "as needed" assistance to DEQ within the constraints of the project budget

Tasks 1 and 2 were completed on February 4 and 5, 2008, and the Task 3 trip report was submitted to DEQ on February 15, 2008. The Task 4 preliminary evaluation of the PGE Proposal (Memo #1) was submitted to DEQ on February 25, 2008. This evaluation focused on the NO_x control technologies that were examined by B&V for the Boardman Plant; however, the evaluation was considered preliminary because answers to most of the questions asked of PGE and B&V at the February meetings had not as yet been provided. The memo cited selective catalytic reduction (SCR) installed costs as the major issue to be resolved and most other comments were fairly minor (i.e., not likely to substantially change the BART determination).

This Task 6 memorandum (Memo #2) documents the results of ERG's complete evaluation of the PGE Proposal, as well as our own feasibility assessment of select technologies for controlling NO_x at the Boardman Plant (Task 5). Memo #2 is organized as follows:

- Summary of Methods and Findings: This section contains a brief overview of the method used by ERG to evaluate the PGE Proposal and assess the various characteristics of each NO_x control technology (i.e., performance, energy and non-air quality impacts, and cost).
- Section 1.0, Control Technologies Selected for Analysis: This section lists and describes the NO_x control technologies reviewed by ERG and contained in the PGE Proposal for the Boardman Plant. Also, the impact of the NO_x controls on the DEQ's requirements pertaining to mercury for Boardman is discussed.
- Section 2.0, ERG's Cost Estimation Methodology: This section describes the inputs and outputs of the cost estimates developed by ERG using the CUECost model. Conclusions are presented regarding the appropriateness of this method for use on Boardman's NO_x control retrofit options.
- Section 3.0, Comparison of PGE Proposed Costs and ERG Costs Estimates for NO_x Control: This section compares the results contained in the PGE Proposal for the range of NO_x controls, to ERG's estimates. This section addresses the significant issue of how best to estimate SCR installed costs for the Boardman Plant in view of widely varying costs that results from various approaches.
- Section 4.0, Conclusions: This section provides ERG's findings with regard to the PGE Proposal for the Boardman Plant's NO_x and mercury control technologies.

SUMMARY OF METHODS AND FINDINGS

Based on the experience of ERG's NO_x control expert and relevant literature, ERG evaluated the performance and energy and non-air quality impacts of the NO_x control technologies identified by DEQ for this analysis, and evaluated in the PGE Proposal for the Boardman Plant, including (combinations of): new low NO_x burners (NLNB), advanced overfire air (AOFA), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). Our findings are as follows:

- With regard to the performance of NLNB with AOFA, ERG acknowledges that the unusual furnace internals at the Boardman Plant (i.e., wing or division walls extending well below the boiler nose) will limit the effectiveness of these controls in reducing NO_x, and finds that the B&V estimate of 0.28 lb/MMBtu does not seem unreasonable.

- With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR at the Boardman Plant under year-round operation would need to be considered in selecting a permit level.
- With regard to SNCR performance, although SNCR installations on boilers have been demonstrated to achieve between 25 and 50 percent reduction in NO_x, very large boilers (>300 MW) generally are limited to lower SNCR removal efficiencies. The Boardman Plant is large and has division walls, noted above, that limit upper furnace mixing. In Memo #1, ERG expressed concern that SNCR might not achieve the 20 to 25 percent that B&V was predicting for Boardman. B&V has since requested a more detailed assessment of the unit by Fuel Tech, the country's leading SNCR vendor and has reduced the estimated performance to18 percent to be conservative.
- With regard to energy and non-air quality impacts, ERG finds that there are no significant impacts from existing/new LNB, AOFA, or SNCR. In general, ERG agrees with the PGE Proposal that SCR has three (potential) adverse impacts as compared to SNCR: an SCR unit requires at least 36 times as much electricity to operate as SNCR; disposal of spent catalysts create hazardous waste (although ERG believes evolving catalyst management practices may minimize this impact); and anhydrous ammonia releases create an additional accidental release hazard. In some cases, utilities have chosen to avoid this hazard by generating ammonia "on demand" from urea, although this involves added capital and operating expense.

ERG's method for evaluating cost of the NO_x control technologies included use of the CUECost estimation program. The CUECost program is widely accepted and used by the utility industry and government agencies for estimating costs for controls applied to coal-fired power plants. While ERG believes that CUECost is appropriate for estimating cost for relatively small construction projects (e.g. NLNB, AOFA and SNCR retrofits for coal-fired power plants), we do not believe that CUECost accurately reflects installed costs for major construction projects, such as SCR and flue gas desulfurization (FGD), for reasons that evolved through this study. These findings are described below.

From the outset, the majority of ERG's attention and effort focused on the probable installed cost of SCR at the Boardman Plant. In our preliminary evaluation (Memo #1), ERG believed that the SCR installed cost estimate provided on page D-9 of the PGE Proposal overstated the likely cost (2007 cost-basis), possibly by as much as a factor of two. We focused on the SCR installed cost because:

- SCR is widely and successfully applied on Powder River Basin (PRB) coal units throughout the country;
- SCR is effective in reducing NO_x to very low levels; and
- SCR represents a substantial increase in installed cost as compared to SNCR (which is the BART technology proposed by PGE).

For quite some time, the power plant NO_x control community has used $100/kW as a rule-of-thumb installed cost for SCR installed on coal-fired power plants. This was based on costs reported for some early installations in the 1990s and early cost studies by the U.S. Environmental Protection Agency (U.S. EPA) and others. As we started this analysis of the PGE Proposal, ERG was aware of three literature papers that addressed SCR installed costs (Hoskins, 2003; Cichanowicz, 2004; Marano and Sharp, 2006) with cost-basis years of 2002, 2003 and 2005, respectively. These papers provided evidence that the $100/kW rule-of-thumb did not correspond to the costs being experienced by utilities installing SCR in the 2002–2005 timeframe. In an initial conference call with DEQ personnel, ERG expressed an opinion that SCR installed costs for Boardman may be on the order of $150/kW or about one half the $309/kW that was contained in the PGE Proposal.

Section 3.0 of this memo contains a discussion of three avenues of analysis that ERG has pursued to evaluate the probable installed cost of SCR at Boardman. These are:

- Bottom-Up installed cost using the CUECost Model with the Chemical Engineering Construction Cost Index for 2007 applied.
- Top-Down literature values obtained from the SCR installed costs as reported in various Internet and subscription sources.
- A current B&V "real" project cost that ERG was permitted to examine (under terms of a confidentiality agreement) in the B&V offices in Overland Park, Kansas.

ERG supplemented these cost sources with literature papers and relevant study findings concerning the general escalation in heavy construction cost resulting from the world-wide commodities bubble and construction labor shortages.

The CUECost program generates an installed cost of $70/kW to $130/kW; however, we feel this does not represent the probable cost of SCR applied to the Boardman Plant.

The top-down literature values analysis is based on a large number of data points including 33 SCR project installed costs provided by PGE and B&V in an April 6, 2008 submission to DEQ. Although there are many data points in this dataset, the quality of the individual points is difficult, and in some cases impossible, to assess. Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004. ERG analyzed the 2007 cost-basis data by eliminating the three highest and three lowest cost projects and one project that was known to be very dissimilar to the Boardman Plant characteristics. The remaining nine projects range from $207/kW to $267/kW, with an average of $227/kW. ERG believes that this is a reasonable representation of 2007 costs of large SCR installations under normal retrofit conditions.

ERG examined the actual cost data (i.e., both the bid cost developed for the project proposal and the actuals from the B&V project accounting system) for a recent SCR project performed by B&V. The total installed cost for this project was $221/kW on a 2007 cost-basis. This project cost falls near the middle of the costs resulting from the analysis of the 2007 top-down literature values described above and thus provides confirmation that the range of $207/kW to $267/kW is reasonable.

Certain retrofit conditions at the Boardman plant tend to increase the installed cost, and others tend to reduce costs. The fact that some boiler modifications will be needed (due to the high flue gas temperature at the economizer outlet) that are not typical of SCR retrofit projects, tends to offset some of the cost-lowering factors present at the Boardman Plant. With all of these factors taken into consideration, ERG concludes that the Boardman Plant SCR installed cost would be at the high end of the $207/kW to $267/kW range cited above (a detailed analysis of this finding is in Section 3.4 of this memo). However, since no detailed design of the Boardman Plant SCR has been carried out, there is a fairly broad uncertainty band associated with all of these cost estimates.

Table 1 of this memo provides a side-by-side comparison of the costs for all NO_x control technologies evaluated in the PGE Proposal, and by ERG using the research and methods described above. Differences in costs range from less than 1 percent (for NLNB) to 100 percent for existing LNB with OFA and SNCR. Differences between PGE and ERG cost estimates for SCR range from 24 percent (SCR with existing LNB and OFA) to 27% (SCR with NLNB and AOFA).

1.0 CONTROL TECHNOLOGIES SELECTED FOR ANALYSIS

DEQ directed ERG to review several specific NO_x controls for potential use at the Boardman Plant. These controls, listed below, were also contained in the PGE Proposal and initially reviewed by ERG in Memo #1 (submitted to the Oregon DEQ on February 25, 2008):

- New low NO_x burners (NLNB)
- NLNB with advanced overfire air (AOFA)
- Existing LNB with OFA and selective catalytic reduction (SCR)
- Existing LNB with OFA and selective noncatalytic reduction (SNCR)
- NLNB with AOFA and SCR
- NLNB with AOFA and SNCR

The remainder of this section discusses the performance (i.e., percent reductions and emission rates in pounds per million BTU [lbs/MMBtu]) and energy and non-air quality environmental impacts for each of the NO_x controls. Also, the potential impacts of each NO_x control on DEQ's existing mercury control requirement for the Boardman Plant are discussed.

1.1 Performance of NO_x Controls

New Low NO_x Burners

Improvements to LNB design since development of the first generation of LNBs have achieved an additional 20 to 40% reduction in NO_x in comparison to first generation LNBs. The PGE Proposal indicates that the Boardman Plant was issued a construction permit in 1977. As part of the permit, PGE utilized first generation low NO_x burners (LNB) in combination with overfire air (OFA) to reduce NO_x emissions. This combination of controls is discussed below.

New Low NO_x Burners with Advanced Overfire Air

Since the early to mid-1990s, boosted overfire air systems (referred to as advanced overfire air or AOFA) began to be operated. This OFA system can be installed over the existing wind boxes for retrofit installations. Advanced OFA systems add air ports to several walls of the furnace, in addition to just the burner walls. Due to fan systems and extra air ports, more flow can be diverted than in the original OFA system. The extensive placement of ports in the AOFA system also allows air to be diverted to a greater area of the furnace interior. The NO_x removal efficiency of the AOFA system ranges from 15 to 25 percent compared to the baseline case. New LNBs in combination with AOFA systems have been demonstrated to achieve NO_x emission levels as low as 0.15 lbs/MMBtu for some wall-fired boilers firing PRB coal. However, for reasons discussed below, ERG does not believe that 0.15 lbs/MMBtu is achievable at the Boardman Plant.

There are a number of instances of NLNB/AOFA retrofits on units that burn PRB coal where the resulting NO_x emission level is reported to be 0.15 lbs/MMBtu. An examination of the individual units involved shows that all but one of the units are tangential-fired with very low pre-retrofit NO_x emission levels. The single wall-fired unit is discussed in a paper prepared by the vendor, Riley Power (Penterson, 2003). The specific unit is not identified in the paper, nor is the owning utility identified. The paper does discuss some characteristics of the unit which are not typical of most wall-fired boilers. Specifically, when the unit was originally started up, it was determined that it could not be fired at its intended full rating. Sixteen of the original burners were removed resulting in a substantial derating and a very low initial NO_x of 0.30 lbs/MMBtu. The initial NO_x at Boardman (0.43 lbs/MMBtu) is more than 40 percent higher than the unit described in the Penterson paper and the achievement of 0.15 lbs/MMBtu at Boardman Plant by retrofitting NLNB and AOFA does not appear feasible.

Also, the furnace internals at the Boardman Plant appear to be rather unusual in that the wing (or division) walls extend well below the boiler nose. More typically, in-furnace pendant pressure parts would extend down to the nose. The Boardman Plant upper furnace has wing-walls that suspend from the furnace roof to about midway down to the furnace floor. They appear also to extend from the front wall to about midway to the back wall and will present problems both in getting good mixing of the AOFA and possible rapid tube corrosion due to the strongly reducing flue gas conditions, if deep-staging is attempted in the Boardman furnace.

The non-typical situation at Boardman Plant will, in the opinion of ERG, limit the effectiveness of NLNB and AOFA in reducing NO_x. Determining exactly how much reduction could be achieved would require detailed computational fluid dynamics (CFD) modeling; however, the B&V prediction of 0.28 lb/MMBtu does not seem unreasonable.

Low NO_x Burners with Overfire Air and Selective Catalytic Reduction

Recent installations on utility boilers have shown that SCR can achieve 70 to more than 90 percent efficiency, and NO_x emission levels as low as 0.05 lbs/MMBtu. Similarly, SCR in combination with LNB with OFA or NLNB with AOFA have been demonstrated to achieve NO_x emissions as low as 0.05 lbs/MMBtu. Most of this experience is with ozone-season units that have a substantial opportunity for off-season maintenance and catalyst cleaning; therefore, the impact of year-round operation would have to be considered in selecting a permit level for the Boardman Plant.

Low NO_x Burners with Overfire Air and Selective Noncatalytic Reduction

SNCR installations in combination with LNB with OFA or NLNB with AOFA on utility boilers have been demonstrated to achieve between 25 and 50 percent reduction. The reduction percentage that can be achieved is extremely unit-specific and fairly large units generally achieve reductions at the low end of the range. ERG has expressed concern that high upper furnace temperatures at the Boardman Plant, and the effect of the wing walls on upper furnace mixing mentioned earlier, might severely limit reductions achievable at the plant. During a meeting at B&V offices in Kansas on April 24, 2008, B&V indicated that they have had Fuel Tech (a leading SNCR vendor) conduct further examination of the Boardman unit. Fuel Tech confirmed that there was an appropriate injection location (in the upper backpass, rather than the usual upper furnace location), and that 25 percent reduction is feasible. B&V said that they were assuming 18 percent in their estimates to be conservative.

1.2 Energy and Non-Air Quality Environmental Impacts

Existing/New Low NO_x Burners, Existing/Advanced Overfire Air, Selective Noncatalytic Reduction

There are no significant energy or non-air quality environmental impacts from use of existing or NLNB, existing or AOFA, or SNCR.

Selective Catalytic Reduction

The PGE Proposal cites three energy and non-air quality environmental impacts for which SCR is disadvantaged when compared to SNCR:

- B&V calculates that the SCR unit will require 36 times as much electric power as SNCR, due to the additional fan power needed to overcome the catalyst bed pressure drop. ERG believes that this figure may be low. CUECost generates a differential of about 100 times for the same SCR-to-SNCR comparison.
- The PGE Proposal cites the disposal of spent catalyst as a hazardous waste as being a non-air quality environmental impact. This may be of little significance, based on evolving catalyst management practices. Catalyst regeneration processes potentially allow for reuse of the catalyst modules for several cycles, making the disposal cost and environmental impact much less than earlier industry estimates.
- The PGE Proposal cites the additional accidental release hazard associated with anhydrous ammonia (for SCR) versus urea solution for SNCR. Although the remote location of Boardman makes this less of an issue when compared to urban and suburban power plants, nevertheless, there is added hazard for plant personnel and the few people that may live or be present in the path of an ammonia plume from the plant. This hazard can be remedied for a price. Today, there are commercially available systems that convert urea to ammonia "on demand", with no significant ammonia inventory present at the facility at any time. As noted, this is an additional capital and operating cost for the SCR installation. It should also be noted that ammonia is a fairly common industrial chemical and refrigerant and there are established safeguards and procedures for its handling and storage.

In general, ERG agrees with the PGE Proposal assessment of these impacts, at least qualitatively.

1.3 Mercury Control Technologies

Additionally, the effect of the NO_x controls on reducing mercury emissions was also evaluated. PGE proposes to retrofit a fabric filter downstream of the existing electrostatic precipitator (ESP) to enhance the control of particulate matter at the Boardman Plant. The PGE Proposal states that this technology selection was driven, in part, by the future need to control mercury emissions with dry sorbent injection. This approach is consistent with the approach taken throughout the industry for power plants burning PRB coal. Because mercury contained in PRB coal flue gas is not readily oxidized by SCR catalysts for subsequent collection in a flue gas desulfurization (FGD) system, virtually all near-term mercury control for PRB units will be through the use of activated carbon injection (or injection of enhanced activated carbon). In a very recent study by The Shaw Group (Wedig et al., 2008) published in the May 2008 issue of Power Magazine, the authors identified a total of 51 PRB plants (8 new and 43 retrofit) that have committed to mercury control, all proposing activated carbon injection.

None of the other NO_x controls considered (i.e., NLNB, AOFA, SNCR) would have any impact on the Boardman baseline mercury emissions. Also, for reasons stated in the previous paragraph, capture of mercury in an FGD system (wet, dry, or semi-dry, would be very small and Boardman, like other PRB coal-fired units, will need to rely on some form of carbon injection for mercury control.

2.0 ERG'S COST ESTIMATION METHODOLOGY

The U.S. EPA's BART guidance (www.epa.gov/air/visibility/pdfs/guidelines_2005_6_24.pdf) recommends: "The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, EPA 453/B-96-001)." Consequently, ERG reviewed the procedures in the available cost estimation methodologies, the OAQPS Cost Manual, and also the CUECost estimation program to determine the most appropriate methodology for providing capital and annual costs. Initially, ERG decided that the CUECost estimation program was more appropriate because it provided costs separated into elements which could be compared to the specific cost elements used by B&V in developing the PGE Proposal. Also, the CUECost program is widely accepted and used by the utility industry and government agencies to provide cost estimates, and it is tailored to air pollution controls applied to coal-fired power plants.

The remainder of this section describes the CUECost input data used by ERG, and provides our conclusions related to CUECost's ability to predict "real world" costs for projects requiring major heavy construction (e.g., SCR) as compared to smaller projects (e.g., NLNB, AOFA, and SNCR) that do not require major structural work or large process equipment. Based on our conclusions, we deviate from a CUECost approach when preparing an independent estimate for SCR installed cost; this is explained in detail below in Section 3.4 of this memo.

2.1 Cost Algorithm Inputs

The CUECost program provides cost estimates for new LNB, SCR, and SNCR. The cost factors for AOFA provided in an earlier analysis conducted by ERG for the Western Regional Air Partnership (WRAP) were used to calculate the capital costs. The WRAP report indicates that in 2005, the installed capital cost for AOFA was $8.80/kW. The total capital investment for the combinations of NO_x controls using AOFA were calculated by adding the AOFA capital costs.

Attachment A lists the inputs necessary to run the CUECost program for NO_x control technologies, and the rationale for use of the different inputs. The attachment also provides the inputs used in the analysis and the source of the input data. After reviewing the PGE Proposal CUECost inputs, ERG concludes that most of the inputs that were used for PGE's CUECost runs were appropriate for the analysis. Consequently, where possible, we used inputs provided by PGE for our assessment. Attachment B contains detailed cost outputs from CUECost for NLNB, AOFA, SNCR, and SCR. Attachment C shows a detailed comparison of the PGE and ERG CUECost estimates for total capital investment of SCR, which is a main area of disagreement (see Section 3.4 for more details on this comparison).

The CUECost program was last updated in 2002. For the outputs to be relevant, ERG escalated the costs to 2007 using Chemical Engineering magazine cost factors.

2.2 Conclusions Regarding the Use of CUECost for the Boardman Analysis

As discussed later in detail in Section 3.4 of this memo, ERG's investigation of SCR installed costs for the 2007 cost-basis year has led us to the conclusion that CUECost does not provide "real world" costs for SCR in the current environment for major construction projects. Similarly, based on a study prepared for the National Lime Association (Sargent and Lundy, 2007) and a study by Cichanowicz for the Utility Air Regulatory Group (Cichanowicz, 2007), there is good evidence that FGD (i.e., another technology requiring heavy construction) installed costs have escalated at an unprecedented rate since about 2004. CUECost, even when inflation-adjusted by applying the current Chemical Engineering Construction Cost Index, appears to produce installed costs that are well below those that appear in the recent literature. However, for relatively "smaller" projects, such as LNB, AOFA, and SNCR retrofits, we believe that estimates developed using CUECost are reasonable.

ERG was not able to determine why CUECost seems unable to generate costs corresponding to current experience; however, Cichanowicz, et al. (Cichanowicz et al., 2006), speculated that early SCR installations may have been misleading due to under-design (that resulted in failure to meet performance objectives) and selection of favorable retrofit units for early installations. Also, some features now considered more or less standard (e.g., large pitch catalyst, popcorn ash screens, static mixers, and provision of a great deal of sootblower capability) were not part of early system designs. Finally, vendors were clearly positioning for the surge of installations in 2002, 2003 and 2004, and substantial cost overruns may have been absorbed by the vendors and constructors, and would not necessarily be reported by the utilities or appear in the literature. In the recent worldwide high-demand environment for industrial construction services and equipment, the opposite effect may be taking place, where engineering firms, constructors and equipment manufactures are bidding with high profit margins and large contingency factors, driving up installed costs.

Although ERG is convinced that CUECost fails to provide "real world" installed costs for major construction projects such as SCR retrofits, we are not able to necessarily extend this to projects that do not require extensive "construction" (e.g., extensive foundations and structural works, ductwork modifications, etc.) and projects where retrofit issues do not heavily influence installed costs. For smaller projects such as NLNB, AOFA and SNCR, largely because we have no evidence to the contrary, we have used CUECost results escalated to 2007 by applying the 2007 Chemical Engineering Construction Cost Index.

3.0 COMPARISON OF PGE PROPOSED COSTS AND ERG COST ESTIMATES FOR NO_x CONTROL

This section compares the PGE proposed costs with the ERG costs for the NO_x control technologies selected for this analysis. Table 1 summarizes the total capital cost in units of $/kW from the PGE Proposal and as estimated by ERG for each NO_x control technology. A discussion of each of the comparisons is provided below for NLNB (Section 3.1), NLNB with AOFA (Section 3.2), SNCR (Section 3.3), and SCR (Section 3.4).

3.1 NLNB Comparison

The capital cost estimates for NLNB from ERG's CUECost run differs by less than 1% of the estimate provided by PGE. This difference was not considered significant and, therefore, not analyzed further.

3.2 NLNB with AOFA Comparison

The difference in total capital cost of NLNB with AOFA between the PGE Proposal and ERG's estimates is due to PGE's use of handling and erection cost factors that are higher than those in CUECost to estimate direct installation costs. The handling and erection factor (50 percent of the purchased equipment cost) is approximately 20 to 30 percent higher than cost factors used in CUECost and in EPA's OAQPS Cost Manual. These additional costs then propagate further when calculating Indirect Costs and Total Capital Investment. The PGE Proposal included costs for the following ancillary equipment: neural network system, NO_x monitoring equipment, water cannon, and modulating orifice for burners. These additional cost items add approximately $8/kW to the total installed cost.

ERG agrees that certain upgrades such as neural networks and burner air controls are part of general system upgrades that allow NLNB with AOFA to achieve and maintain optimum performance. Also, PGE reported that slagging has been a recurring problem when the current OFA system is operated continuously. Water cannons have been used extensively for PRB units throughout the country. ERG's cost is based on a combination of the CUECost result ($28/kW) and the cost of the ancillary equipment noted above ($8/kW) for a total of $36/kW. The PGE Proposal cost is $53/kW, or about 47% higher.

Table 1. Comparison of PGE Proposed Costs and ERG Costs for NO_x Control at the Boardman Plant

Control Technology	Cost Estimate in $/kW		% Difference	Notes
	PGE	ERG		
NLNB	18	18	< 1%	CUECost and PGE estimates are essentially the same.
NLNB with AOFA	53	36	47%	PGE cost is much higher than CUECost results. PGE added equipment items not included in CUECost. ERG agrees that these items are warranted and that the probable cost is about $8/kW. This cost was added to the CUECost result to arrive at the ERG estimate.
Existing LNB with OFA + SNCR	28	14	100%	ERG cost is based on CUECost and confirmed by leading SNCR vendor public statement. ERG does not know the basis of PGE's estimate and cannot duplicate it.
NLNB with AOFA + SNCR	81	50	62%	Cost is based on adding the NLNB with AOFA cost to the SNCR cost, above.
Existing LNB with OFA + SCR	309	250	24%	ERG cost is based on the high end of the range of costs ($207/kW to $267/kW) that ERG found to be reasonable based in the analysis described in Section 3.4 of this memo.
NLNB with AOFA + SCR	362	286	27%	Costs are based on summing the cost of "stand-alone" SCR with the cost of NLNB/AOFA. Probably costs should be slightly lower because of reduced inlet NO_x.

ERG does not have information that would support the higher erection factor used by PGE as compared to the CUECost default values. However, we do note again that there has been rapid escalation in construction costs in recent years for SCR that does not seem to be captured by CUECost using the Chemical Engineering Cost index.

3.3 SNCR Comparison

For the option of using the existing LNB with OFA along with a new SNCR, PGE's Proposal indicated that CUECost was used to calculate costs of the SNCR system. However, PGE's CUECost outputs could not be duplicated using the inputs provided in the PGE Proposal. Insufficient information was provided to fully assess the reason for the differences. The costs estimated by PGE for reagent storage, handling, injection and controls were $5,100,000 compared to the CUECost output of $1,730,000. Air heater modifications calculated by PGE were $2,835,000 compared to the CUECost output of $1,400,000. These additional costs then propagate further when calculating indirect costs and total capital investment.

Fuel Tech's Dr. Bill Sun, a longtime expert on SNCR, recently placed SNCR installed costs at \$5 to \$20/kW (Sun, 2007). The CUECost estimate of \$14/kW falls comfortably within the range indicated by Fuel Tech. This cost would apply to both the existing LNB with OFA and NLNB with AOFA, as SNCR capital costs are relatively insensitive to initial NO_x emissions levels. The PGE Proposal contains an installed cost of \$28/kW for SNCR (which we cannot reproduce); this is at least 50 percent higher than the CUECost estimate for SNCR.

3.4 SCR Comparison

ERG reviewed the SCR installed cost contained in the PGE Proposal. The review has involved a number of information-gathering steps and discussions with DEQ, PGE and B&V. The following activities have taken place since the start of the project in January 2008:

- January 18 - After a brief review of the BART Proposal, ERG and DEQ conducted a conference call to plan initial steps. During this call ERG gave its initial reaction to the PGE Proposal and cited the SCR installed costs as, in our opinion, well above costs appearing in the literature.
- February 4 - ERG attended the Stakeholder Meeting at Stoel Rives LLP. B&V presented the main points of the BART Proposal and ERG provided 14 questions in writing. These questions were combined with dozens of other questions raised by the stakeholders attending the meeting.
- February 5 - ERG attended a tour of the Boardman Plant.
- February 15 - ERG submitted a trip report covering the February 4 meeting and the February 5 plant tour.
- February 15 - ERG received and reviewed the B&V response to ERG question #2, which asked for the plant, economic, and NO_x inputs used for the CUECost model runs that were used in the PGE Proposal. In some ways, the response confused these issues rather than clarifying them, since the data and discussion in the response did not correspond to the discussion in the PGE Proposal (i.e., different inlet NO_x, different percent removal).
- February 25 - ERG submitted Memo #1 to DEQ, discussing the ERG review of the PGE Proposal. SCR installed cost was identified as the primary concern. Most other comments were relatively minor.
- March 23 - ERG received and reviewed the PGE/B&V responses to 101 questions that were recorded at the February 4 and 5 meetings.
- April 6 - ERG received and reviewed a B&V discussion of current and historical SCR installed costs. This submission included installed costs for 33 SCR projects (both single unit and multiple unit projects) with the cost-basis year, unit size, and installation year. These were obtained from the open literature and subscription sources. Both actual completed projects and future (estimated cost) installations are included.
- April 24 - ERG attended a meeting and discussion at B&V offices in Kansas. At this meeting, B&V presented a detailed cost estimate for a current SCR project that is similar enough in size as to be relevant to the potential Boardman installed cost.

The primary issue is: ***How to estimate SCR installed cost for the Boardman Plant in view of widely varying costs that result from various sources and approaches?***

We examined three fundamentally different costing approaches to address this issue:

- Bottom-up installed cost using the CUECost Model
- Top-down literature values
- B&V "real" project cost

In addition, we examined the general escalation of construction costs due to the commodities bubble and labor shortages. These approaches and the general escalation of construction costs as related to SCR are discussed in detail below.

Bottom-Up Installed Cost Using the CUECost Model

CUECost is a widely-used, U.S. EPA-developed cost model for air pollution controls applied to coal-fired power plants. When the model is run with Boardman-specific technical inputs, the default economic inputs, a "difficult" retrofit factor and escalated to 2007 dollars, the result for Boardman is about $100/kW. Since the developers of CUECost specifically caution that the level of detail involved results in a plus-or-minus 30 percent estimate, the CUECost estimate for the Boardman Plant would actually be $70/kW to $130/kW. However, a number of recent studies of actual installed costs for completed installations and estimates for near-term future installations call into question the direct use of CUECost in today's construction environment. For reasons noted below, it is ERG's opinion that the CUECost model does not generate "real world" SCR installed cost estimates.

Top-Down Literature Values

There are three fairly recent literature papers that address SCR installed costs (Hoskins, 2003; Cichanowicz, 2004; Marano and Sharp, 2006). In a paper prepared for the Utility Air Regulatory Group, Cichanowicz compiled SCR installed costs from the same three papers (Cichanowicz, 2007). Also, Internet searches produced a number of other anecdotal examples of recent plant-specific costs. Although there are many data points in this dataset, the quality of the individual points is difficult, and in some cases impossible, to assess. Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004.

In their April 6 submission, B&V compiled installed costs for 33 SCR projects, including both single unit and multiple unit installations. The average SCR installed cost for the 2007 projects was $242/kW, and B&V concluded that these data are consistent with their Boardman Plant estimate of $309/kW when the proposed Boardman boiler modifications, at $65/kW, are added. (Note: the Boardman Proposal [at page D-9] includes the cost of NLNB and AOFA along with the SCR cost, resulting in a total of $362/kW for the combined technologies.)

ERG examined the 33 individual data points (installed cost, cost-basis year) and determined that several of the critical (2007 cost-basis) data points are skewed somewhat to the high side. For example, 6 of the data points for 2006 represent projects at Progress Energy's Ancolote and Crystal River plants. The data for cost-basis year 2007 contains these same projects, escalated by 70 percent based on a blanket statement by a Progress Energy official that the cost of new air pollution controls have "jumped 70% from their 2006 submission" (to the Florida Public Service Commission). An examination of the source document shows that the 2006 submission actually contained estimates with a 2005 cost-basis. Also, the implied 70 percent escalation from 2006 to 2007 is in conflict with a statement by Kentucky Utilities (before the Kentucky Public Services Commission) that the installed cost estimate of SCR for Ghent Unit 2 had increased by 21 percent from 2006 to 2007. The 70 percent escalation figure is also inconsistent with a number of other papers (see below) that address the general cost escalation for various types of utility construction in the current environment.

Two of the critical 2007 cost-basis data points were contained in the BART proposals for Gerald Gentleman Units 1 and 2 ($334/kW) and Nebraska City Unit 1 ($376/kW). In both cases, the estimate was provided by architectural and engineering firm HDR. The estimates were described as based on 2002 vendor quotes for major equipment, adjusted for capacity (the quotes were not for the specific plants involved), escalated to 2007 (by applying a 68 percent escalation factor), doubled to account for construction costs, and multiplied by a 25 percent contingency factor. ERG does not accept that these very crudely developed costs represent useful data in evaluating cost of the Boardman Plant retrofit.

Finally, an examination of the year-to-year escalation implied by the 33 data points provided by B&V calls into question the quantitative use of the data (though it is certainly useful in a qualitative sense.). For the B&V dataset, the year-to-year changes in historical average installed costs are:

- 2002 to 2003 = +80 percent
- 2003 to 2004 = +76 percent
- 2004 to 2005 = +25 percent
- 2005 to 2006 = -37 percent
- 2006 to 2007 = +62 percent

Obviously, these year-to-year variations, including a drop in cost of 37 percent from 2005 to 2006, are an indication that these data are not useful in any given year in a quantitative sense. They do, however, support the contention that the last several years have seen construction cost escalation that is significantly above the general consumer inflation rate in recent years.

To more closely examine these data in a quantitative sense, ERG eliminated the three highest (including the afore mentioned HDR estimates) and three lowest estimates contained in the 16 projects which make up the 2007 basis-year data. We also eliminated the WE Energies' Oak Creek Units 5 and 6 project since these are small, tail-end systems. The remaining nine projects are fairly tightly grouped, providing some comfort that they represent "typical" installations, rather than outliers. **These projects range from $207/kW to $267/kW, with an average of $227/kW.** The fact that the average is very close to the B&V "real" project cost discussed below tends to confirm that this range ($207/kW to $267/kW) is a reasonable representation of 2007 costs of large SCR systems and normal retrofit conditions.

B&V "Real" Project Cost

At an April 24, 2008, meeting at the B&V offices, an ERG engineer was presented with detailed estimates for two very recent B&V SCR installations. After examining the "specifics" of one of the projects, ERG concluded that it was too different (i.e., much smaller, hot-side ESP, low-dust SCR) to provide a relevant data point for the Boardman Plant retrofit. The second plant was sufficiently close in "specifics" to the Boardman Plant to be relevant. Clearly, the cost details were based on B&V actual costs, and were not prepared specifically for ERG's visit. They correspond roughly to 2007 dollars since the project start was mid-2006 and it is now just wrapping up. B&V provided the estimate for this same unit, reformatted to correspond to the line items on page D-9 of the PGE Proposal.

The B&V "real" project cost of $221/kW that was provided in the D-9 format exhibits some line-by-line differences when compared to the Boardman Plant SCR estimate prepared by B&V for PGE. These differences include higher total purchased equipment costs, lower total direct installation costs, and a much higher cost for site preparation and buildings at the Boardman Plant. The most significant difference the Boardman Plant estimate and the B&V "real" project cost is the $65/kW added to account for boiler modifications to reduce the SCR flue gas inlet temperature. Also, the Boardman BART Proposal SCR estimate includes an additional $53/kW for NLNB with AOFA. ERG believes that the benefit of the NLNB with AOFA system (i.e., lower SCR inlet NO_x) is not properly reflected in the PGE Proposal's SCR cost estimate.

In spite of some of the differences cited above, ERG believes the "real" project cost data that were reviewed at the B&V offices on April 24, 2008, support the PGE/B&V position that CUECost, when run with default values and an escalation factor, does not generate "real world" SCR installed costs for a 2007 cost-basis year.

<u>General Escalation of Construction Costs due to the Commodities Bubble and Labor Shortages</u>

In addition to the three costing approaches described above, ERG considered a fourth factor in analyzing the Boardman Plant SCR estimate contained in the PGE Proposal. In their April 6, 2008 submission of historical SCR installed cost data, B&V included two recent articles that deal with rapidly escalating construction in the utility industry (Chupka and Basheda, 2007; Schimmoller, 2007). Although these articles do not address SCR specifically, they do give a clear sense that construction costs are escalating at a rate well above historical norms. In a report prepared for the National Lime Association, Sargent and Lundy pegged the recent escalation of FGD installed costs at 25 percent per year (Sargent and Lundy, 2007) (Note: FGD retrofits involve the same type of major structural work, large process equipment and retrofit issues that are present with SCR installations.). As noted earlier, Kentucky Utilities estimated an increase of 21 percent for the Ghent Unit 2 SCR cost from a 2006 to a 2007 cost basis. All of these are indications that the effect of world demand for construction materials, equipment, and labor are exerting a strong upward pressure that has impacted SCR installed costs in the U.S.

<u>Summary of SCR Cost Analysis</u>

It is ERG's opinion, based on a distillation of the three cost approaches discussed above and the general rapid cost escalation environment, that the 2007 installed costs for SCR range from $207/kW to $267/kW, barring any extremely favorable or unfavorable site-specific conditions.

In the Boardman case, there are factors that would tend to push costs toward the high end of the range and other factors that would tend to reduce costs. Some of the factors that tend toward higher cost include:

- Use of PRB coal (as compared to bituminous coal);
- The Boardman Plant's remote location and its impact on labor availability and cost;
- The higher-than-normal structural bridge needed to span the ESP; and
- The boiler modifications needed to adjust inlet flue gas temperatures.

Some of the cost-reducing factors include:

- A unit size that is large enough to provide economy of scale, but small enough to fit the catalyst box between the unit and the stack;
- A single-unit plant with much clear space around the rear of the plant; and
- (Importantly) the low inlet NO_x and low removal efficiency specified in the PGE Proposal.

Although some of the site-related factors are favorable (e.g., clear space, single unit plant), the major complicating factor is the boiler modifications for flue gas temperature adjustment, which B&V places at $65/kW. ERG believes, based on conversations with B&V personnel, that B&V has not analyzed this cost in detail (nor has ERG). ERG notes that, in general, all SCR retrofits require ductwork modifications at the rear of the boiler and in many cases, an economizer bypass is included, thus some of the costs associated with fitting the SCR into the boiler/airheater train are already contained in SCR estimates. Anecdotal information on pressure part replacement projects (from the Internet) gives us the impression that the B&V estimate is high, but in the absence of design and cost details, ERG is unable to quantitatively assess this. ERG does agree that some significant cost is involved and that it would tend to push the Boardman installed cost toward the upper end of the range cited above ($207/kW to $267/kW). Bearing in mind the broad uncertainty band associated with all of the estimates, ERG selected a "round number" cost of $250/kW as our Boardman Plant SCR installed cost.

4.0 CONCLUSIONS

The following are ERG's conclusions regarding the NO_x control technologies in the PGE Proposal:

- Appropriate NO_x technologies were included in the analysis.
- The control level estimate for NLNB with AOFA is reasonable. PGE and B&V enlisted Fuel Tech to more closely examine the Boardman Plant and confirm SNCR performance. The resulting B&V estimate of 18 percent control is reasonable. SCR units can achieve control to the 0.05 lbs/MMBtu level, but not necessarily meet a 0.05 limit. Most of SCR experience is with ozone-season units that are afforded significant off-season opportunity for maintenance and catalyst cleaning. The impact of year-round operation would have to be considered in selecting a permit limit for Boardman.
- NLNB with AOFA costs are reasonable.
- ERG finds that the B&V's estimated installed cost for SNCR is high by at least 50 percent. ERG's estimate (based on CUECost) is $14/kW versus the B&V cost of about $28/kW.

- ERG finds that the contention by PGE and B&V that SCR installed costs have escalated extremely rapidly in recent years is supported by a number of literature sources. For reasons not fully clear, CUECost does not capture this recent surge in installed cost, even when the most recent Chemical Engineering Cost Index is applied.
- ERG's analysis of the 2007 cost for retrofitting SCR at the Boardman Plant is based on literature information and on data provided by PGE and B&V. We find a cost of about \$250/kW versus the PGE and B&V estimate of \$309/kW to be reasonable in view of recent similar installations and literature estimates.
- Future mercury control is appropriately addressed by the proposed fabric filter. Since mercury oxidation across an SCR and subsequent collection in an FGD system is relatively ineffective for PRB coal, mercury control at Boardman will likely entail activated carbon injection (or some other dry sorbent) followed by collection in a fabric filter. The other NO_x technologies considered (NLNB, AOFA, SNCR) will not influence the Boardman baseline mercury emissions or future mercury controls.

5.0 REFERENCES

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Attachment A

Inputs Used for CUECost

CUECost INPUTS			
Description	**Units**	**Input 1**	**Source**
General Plant Technical Inputs			
Location – State	Abbrev.	OR	PGE report
MW Equivalent of Flue Gas to Control System	MW	584	PGE report
Net Plant Heat Rate	Btu/kWhr	9,817	PGE report
Plant Capacity Factor	%	85%	PGE report
Total Air Downstream of Economizer	%	117%	PGE report
Air Heater Leakage	%	11%	PGE report
Air Heater Outlet Gas Temperature	▯	297	PGE report
Inlet Air Temperature	▯	80	PGE report
Ambient Absolute Pressure	In. of Hg	29.18	PGE report
Pressure After Air Heater	In. of H_2O	-13	PGE report
Moisture in Air	lb/lb dry air	0.01362	PGE report
Ash Split:			
Fly Ash	%	80%	PGE report
Bottom Ash	%	20%	PGE report
Seismic Zone	Integer	1	PGE report
Retrofit Factor	Integer	1.6	PGE report
(1.0 = new, 1.3 = medium, 1.6 = difficult)			
Select Coal	Integer	8	PGE report
Is Selected Coal a Powder River Basin Coal?	Yes / No	Yes	PGE report
Economic Inputs			
Cost Basis -Year Dollars	Year	2007	
Service Life (levelization period)	Years	15	
Inflation Rate	%	3%	CUECost default
After Tax Discount Rate (current $'s)	%	9%	CUECost default
AFDC Rate (current $'s)	%	11%	CUECost default
First-year Carrying Charge (current $'s)	%	22%	CUECost default
Levelized Carrying Charge (current $'s)	%	17%	CUECost default
First-year Carrying Charge (constant $'s)	%	16%	CUECost default
Levelized Carrying Charge (constant $'s)	%	12%	CUECost default
Sales Tax	%	6%	CUECost default
Escalation Rates:			
Consumables (O&M)	%	3%	CUECost default
Capital Costs:			
Is Chem. Eng. Cost Index available?	Yes / No	Yes	
If "Yes" input cost basis CE Plant Index.	Integer	525.4	CE Cost Index
If "No" input escalation rate.	%	3%	
Construction Labor Rate	$/hr	$35	PGE report
Prime Contractor's Markup	%	3%	PGE report
Operating Labor Rate	$/hr	$30	PGE report
Power Cost	Mills/kWh	65.3	DOE website for 2006
Steam Cost	$/1000 lbs	3.5	PGE report
NO_x Control Inputs			

CUECost INPUTS			
Description	**Units**	**Input 1**	**Source**
Selective Catalytic Reduction (SCR) Inputs			
NH_3/NO_x Stoichiometric Ratio	NH_3/NO_x	1.05	PGE report
NO_x Reduction Efficiency	Fraction	0.90	
Inlet NO_x	lbs/MMBtu	0.426	PGE report
Space Velocity (Calculated if zero)	1/hr	0	PGE report
Overall Catalyst Life	years	3	PGE report
Ammonia Cost	$/ton	400	Price for 2007
Catalyst Cost	$/ft3	169.9	PGE report
Solid Waste Disposal Cost	$/ton	10	PGE report
Maintenance (% of installed cost)	%	1.5%	CUECost default
Contingency (% of installed cost)	%	20%	CUECost default
General Facilities (% of installed cost)	%	5%	CUECost default
Engineering Fees (% of installed cost)	%	10%	CUECost default
Number of Reactors	integer	2	PGE report
Number of Air Preheaters	integer	1	PGE report
Selective NonCatalytic Reduction (SNCR) Inputs			
Reagent	1:Urea 2:Ammonia	1	PGE report
Number of Injector Levels	integer	3	PGE report
Number of Injectors	integer	18	PGE report
Number of Lance Levels	integer	0	PGE report
Number of Lances	integer	8	PGE report
Steam or Air Injection for Ammonia	integer	1	PGE report
NO_x Reduction Efficiency	Fraction	0.50	
Inlet NO_x	lbs/MMBtu	0.426	PGE report
NH_3/NO_x Stoichiometric Ratio	NH_3/NO_x	1.2	PGE report
Urea/NO_x Stoichiometric Ratio	Urea/NO_x	1.2	PGE report
Urea Cost	$/ton	315	PGE report
Ammonia Cost	$/ton	450	PGE report
Water Cost	$/1,000 gal	2	PGE report
Maintenance (% of installed cost)	%	1.5%	CUECost default
Contingency (% of installed cost)	%	20%	CUECost default
General Facilities (% of installed cost)	%	5%	CUECost default
Engineering Fees (% of installed cost)	%	10%	CUECost default
Low NO_X Burner Technology Inputs			
NO_x Reduction Efficiency	fraction	0.35	
Boiler Type	T:T-fired, W:Wall	W	PGE report
Retrofit Difficulty	L:Low, A:Average, H:High	A	
Maintenance Labor (% of installed cost)	%	0.8%	CUECost default
Maintenance Materials (% of installed cost)	%	1.2%	CUECost default

Attachment B

CUECost Outputs

SCR (high-dust) – Preliminary		Case1
Ammonia Injection Rate	lb/hr	949
Space Velocity	1/hr	1,873
Gross Catalyst Volume	ft^3	39,736
SCR Capital Costs		Case1
Cost Basis (Year)	→	***2007***
Reactor Housing and Installation	$	6,933,702
Ammonia Handling and Injection	$	2,034,420
Flue Gas Handling:Ductwork and Fans	$	7,222,232
Air Preheater Modifications	$	1,828,819
Misc. Other Direct Capital Costs	$	604,355
Equipment Capital Cost Subtotal	$	$18,623,527
Instruments & Controls	$	$372,471
Taxes	$	$1,117,412
Freight	$	$931,176
Total Direct Cost		$21,044,586
Total Direct Cost with Retrofit Factor	$	$33,671,337
General Facilities	$	$1,683,567
Engineering Fees	$	$3,367,134
Contingency	$	$6,734,267
Total Plant Cost (TPC)	$	$45,456,305
Total Plant Cost (TPC) w/ Prime Contractor's Markup	$	$46,819,994
Total Cash Expended (TCE)	$	$45,469,545
Allow. for Funds During Constr. (AFDC)	$	$4,985,542
Total Plant Investment (TPI)	$	$50,455,086
Preproduction Costs	$	$1,215,710
Inventory Capital		
Initial Ammonia(60 days)	$	$232,401
Initial Catalyst	$	$6,751,206
Total Capital Requirement (TCR)	$	**$58,654,404**
	$/kW	$100
SCR O&M Costs		Case1
Cost Basis (Year)	→	***2007***
Ammonia	$/yr	1,413,774
Catalyst Replacement	$/yr	2,250,402
Catalyst Disposal	$/yr	3,179
Electricity	$/yr	1,041,331
High-dust SCR Steam	$/yr	93,969
Operating Labor	$/yr	134,190
Supervisory labor	$/yr	***20,128***
Maintenance	$/yr	681,845
Total O&M Costs	$/yr	**5,618,690**
taxes, insurance, administrative	$/yr	$2,346,176
capital recovery	$/yr	$6,439,938
Total Annual Cost	**$/yr**	**$12,078,756**

SNCR - Preliminary		**Case1**
Number of Wall Injectors	integer	18
Number of Lances	integer	8
Urea Injection Rate	lb/hr	1905
Ammonia Injection Rate	lb/hr	1085
SNCR Capital Costs		Case1
Cost Basis (Year)	→	***2007***
Urea Based SNCR Costs		
Urea Storage & Handling	$	$485,138
Urea Injection	$	$983,103
Controls/Miscellaneous	$	$260,286
Air Heater Modifications	$	$1,394,942
Ammonia Based SNCR Costs		
Ammonia Storage, Handling, Injection, Controls	$	$0
Air Heater Modifications	$	$0
Total Direct Cost	$	$3,123,469
Total Direct Cost with Retrofit Factor	$	$4,997,551
General Facilities	$	$249,878
Engineering Fees	$	$499,755
Contingency	$	$999,510
Total Plant Cost (TPC)	$	$6,746,693
Total Plant Cost (TPC) w/ Prime Contractor's Markup	$	$6,949,094
Total Cash Expended (TCE)	$	$6,748,659
Allow. for Funds During Constr. (AFDC)	$	$739,962
Total Plant Investment (TPI)	$	$7,488,620
Preproduction Costs	$	$386,037
Inventory Capital	$	$367,247
Freight		
Total Capital Requirement (TCR)	$	**$8,241,904**
	$/kW	$14.1
SNCR O&M Costs		Case1
Cost Basis (Year)	→	***2007***
Operating and Supervisory Labor	$/yr	65,700
Maintenance Labor and Materials	$/yr	101,200
Reagent	$/yr	2,234,084
Electricity	$/yr	8,825
Water	$/yr	33,954
Steam (for steam atomization)	$/yr	-
Total O&M Costs	$/yr	**2,443,763**
CR		**904,917**
Total Annual Cost		**3,348,680**

Low NO_x Burner Technology Capital Costs		Case1
Cost Basis (Year)		***2007***
Total Capital Requirement with Retrofit (TCR)	**$**	**$10,445,451**
	$/kW	$17.9
Low NO_x Burner Technology O&M Costs		Case1
Cost Basis (Year)		***2007***
Maintenance Labor	$/yr	83,564
Maintenance Materials	$/yr	125,345
Control, Administration, Overhead	$/yr	25,069
Total O&M Costs	$/yr	**233,978**
CR		**1,146,854**
Total Annual Cost		1,380,833

Attachment C

Comparison of PGE Proposal Using CUECost and ERG CUECost Results for SCR

Cost Category	Subcategory	Cost Item	PGE	CUECost (2007)	Comment
Direct Costs	**Purchased Equipment Cost (PEC)**	Reactor Housing	$5,580,000	$6,933,702	
		Ammonia Handling and Injection	2,589,000	2,034,420	
		Initial Catalyst and Ammonia	4,750,000	6,983,607	
		Flue Gas Handling System	6,500,000	7,222,232	
		Air Preaheater Mod.	2,835,000	1,828,819	
		Electical System Mod.	2,261,000		
		ID Fans	3,658,000		
		Ash Handling System	3,100,000		
		Miscellaneous Direct Capital costs		604,355	
		Total Capital Cost	*$31,273,000*	*$25,607,134*	
		Instruments and Controls	3,127,300	372,471	PGE used 10% of Capital Cost, CUECost uses 2%
		Freight	1,563,650	931,176	
		Taxes		1,117,412	
		Total PEC	**$35,963,950**	**$28,028,193**	
	Direct Installation Costs (DIC)	Foundation and Support	$13,666,301		
		Handling and erection	13,306,662		
		Electrical	8,990,988		
		Piping	2,697,296		
		Insulation	3,596,395		
		Painting	359,640		
		Demolition	6,113,872		
		Relocation	4,315,674		
		Retrofit Cost		$12,626,751	

Cost Category	Subcategory	Cost Item	PGE	CUECost (2007)	Comment
		Total DIC	**$53,046,826**	**$12,626,751**	
		Site Preparation	**2,000,000**		
		Buildings	**500,000**		
		Total Direct Costs	***$91,510,776***	***$40,654,944***	
Indirect Costs	Engineering		$10,981,293	$3,367,134	
	Owner's Cost		4,575,539		
	Construction Management		9,151,078		
	Start-up and spare parts		2,745,323		
	Performance Test		200,000		
	Contingencies		13,726,616	6,734,267	
	Contractors Markup			1,363,689	
	General Facilities			1,683,567	
		Total Indirect Costs	***$13,148,657***	***$13,148,657***	
		Allowance for Funds During Construction	***17,926,000***	***4,985,542***	
		Boiler Heat Transfer Surface Area Replacement	***$40,000,000***		
		Preproduction Costs		***$1,215,710***	
Total Capital Investment Cost			**$190,816,626**	**$60,004,853**	

Weber, Steve F.

From: Weber, Steve F.
Sent: Monday, October 06, 2008 11:15 AM
To: Golden.Kevin@epamail.epa.gov; Tim Allen (tim@den.nps.gov); John_Notar@nps.gov
Cc: O'Clair, Terry L.; Mount, Dana K.; White, Rob J.
Subject: Updated ND Regional Haze Modeling Protocol (Draft)

Hello Kevin, John, Tim

Attached is an updated draft of the proposed North Dakota modeling protocol for RH reasonable progress goals. Note that recent changes are highlighted with blue text.

We would appreciate your review and comments on the updated protocol.

Thanks.

Steve

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ND Dept of Health
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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.

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[9] See Reference 8.

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

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

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

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

[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 600°F temperature for the reheated flue gas must be justified.

BMcD Response:

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

SCR Process Design Temperatures

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

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

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

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

BMcD Response:

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

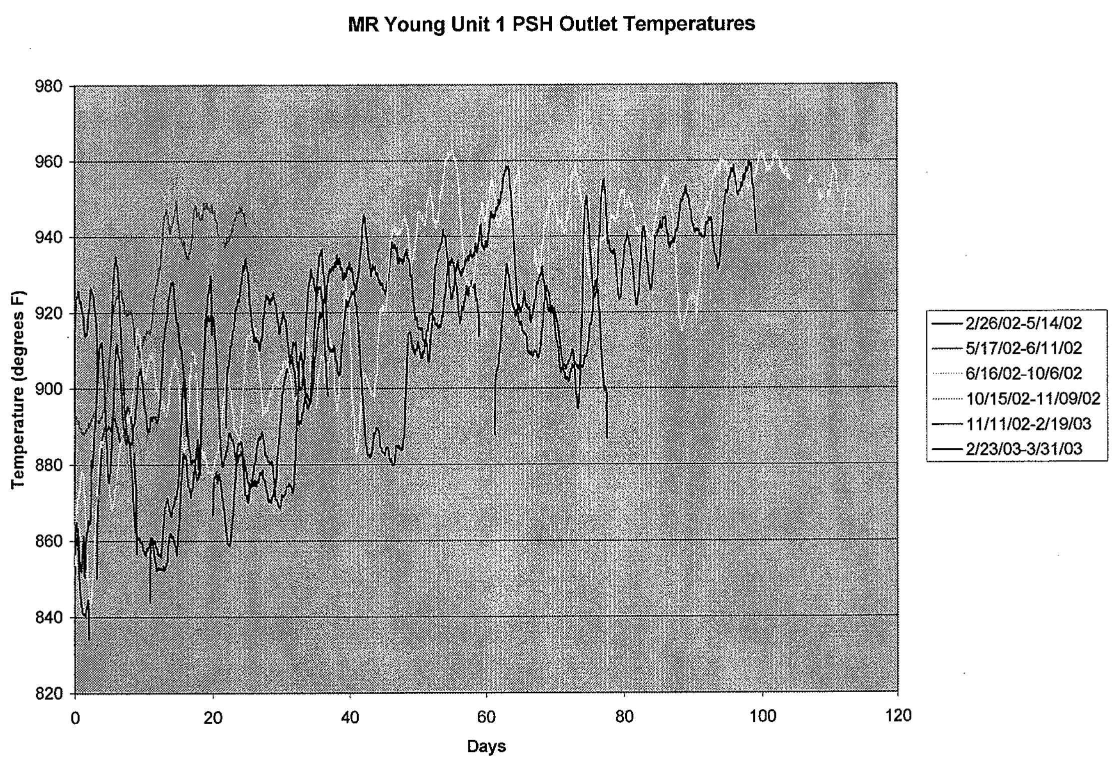
NDDH Request #10: Provide additional clarification and technical justification regarding Minnkota's determination that the units at MRYS are boiler limited and cannot generate additional steam for flue gas reheating purposes.

BMcD Response:

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

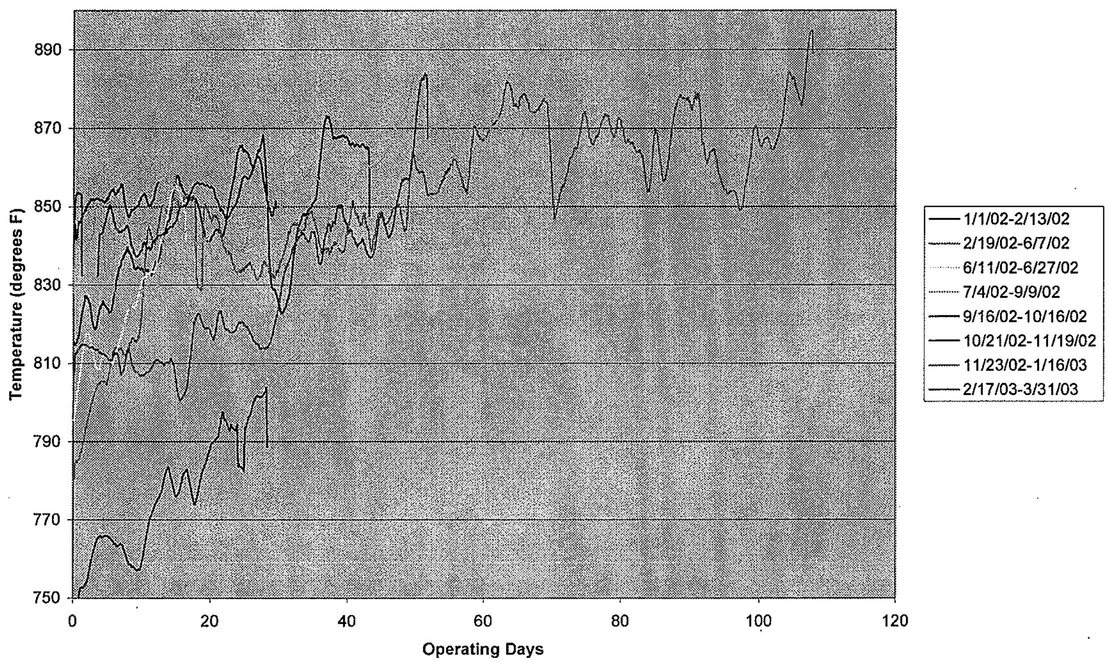
Because of the firing type (cyclone) and characteristics of North Dakota lignite burned and resulting flue gas emissions and ash produced at MRYS, the amount of fouling of the heat-absorbing surfaces within the boiler system is severe. These fouling conditions cause high exit flue gas temperatures that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

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



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

MR Young Unit 2 Economizer Outlet Temperatures



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

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

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

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

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

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

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

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

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

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

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

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

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

REFERENCES

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

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

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

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

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

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

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

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

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

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

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

ATTACHMENTS

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

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

3. ERRATA Sheet:

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

ENCLOSURES:

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

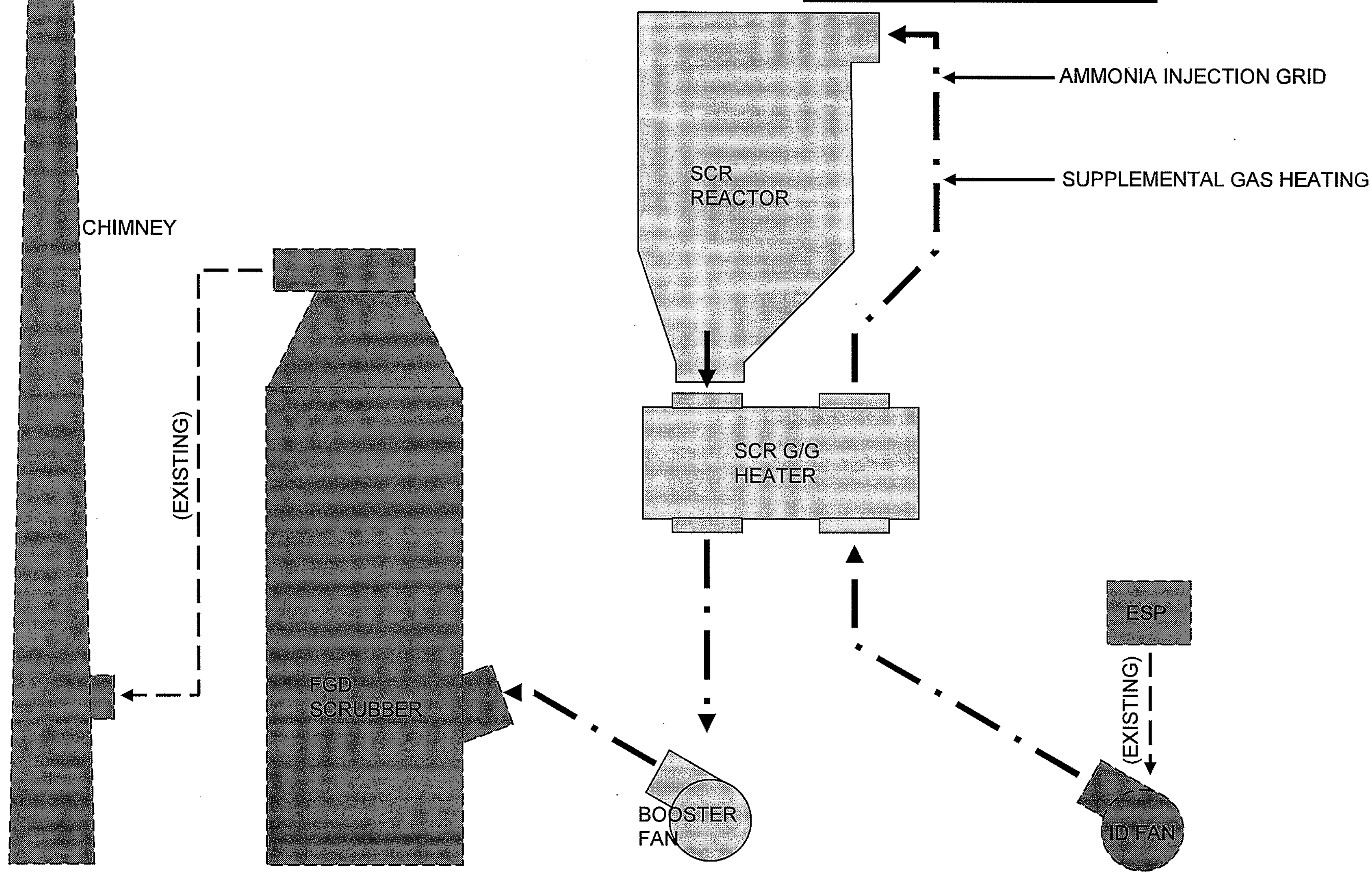
B. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009, revised February, 2010.

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

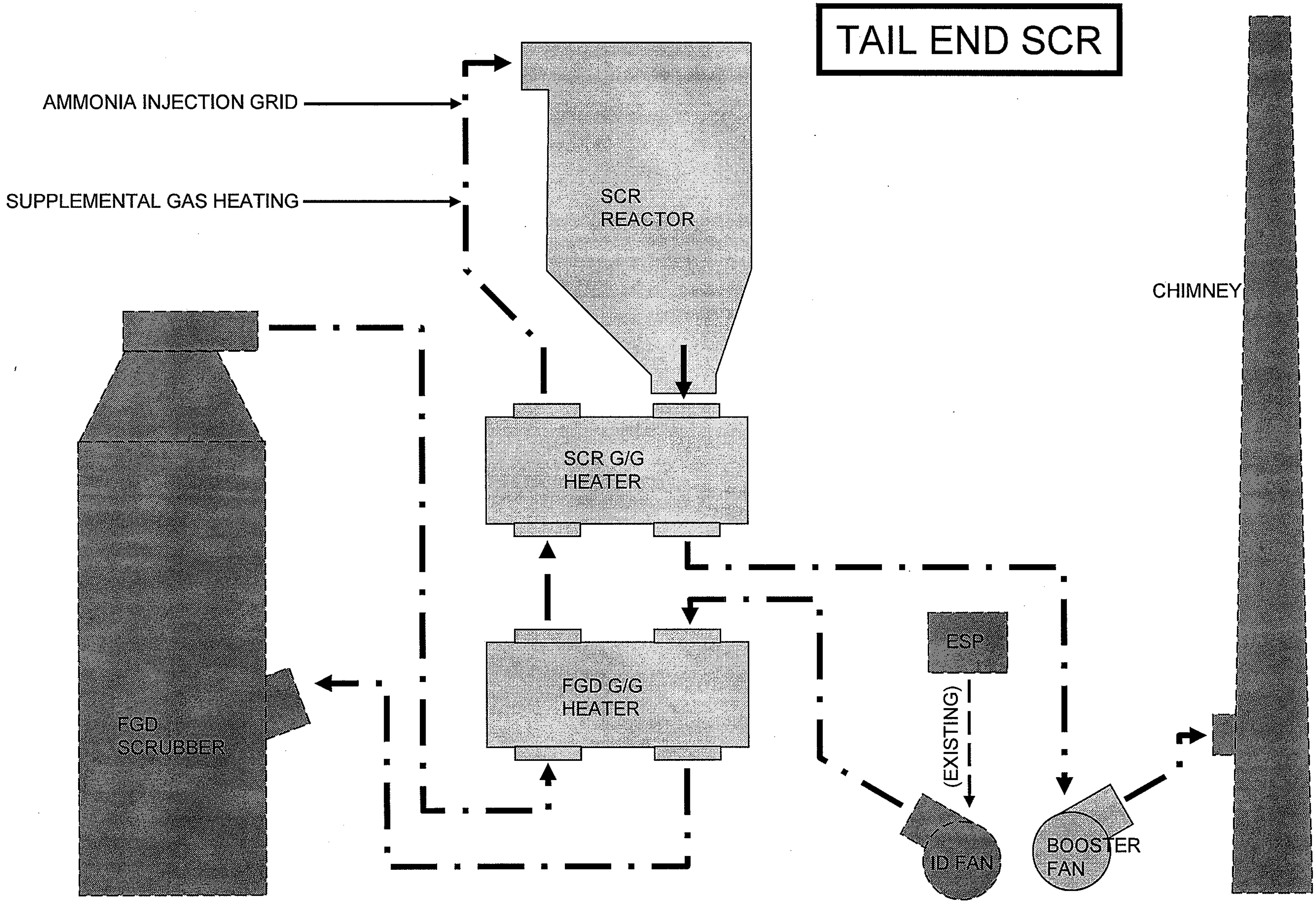
D. Confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit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

SKETCH SK - FD1

LOW DUST SCR



SKETCH SK – FD2



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.

GREAT RIVER
ENERGY

February 9, 2010

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

Dear Lew,

Great River Energy (GRE) respectfully submits our response to questions raised by US EPA concerning ammonia in fly ash relevant to our Coal Creek Station (CCS). To address the issues raised by Amy Platt of US EPA in a November 30, 2009 email message to Tom Bachman of NDDH, GRE provides the following responses:

1. Response to Amy Platt's email
2. Fly Ash usage and properties

Response to Amy Platt's email

Amy Platt's email references Dynegy's Baldwin Energy Complex and Progress Energy's Roxboro Generating Station as facilities that have post combustion NOx control and market their fly ash. Both facilities have Selective Catalytic Reduction (SCR) installed, not Selective Non-Catalytic Reduction (SNCR) technology. It is typical for SCR technology to operate with lower ammonia injection and slippage rates than comparable SNCR technology. With SCR technology additional mixing and chemical reaction assistance is introduced in the catalyst packing resulting in reduction in NOx emissions. SNCR technologies require additional ammonia injection to ensure contact with the NO_X molecules in the flue gas, as they do not benefit from additional mixing or the benefit of enhanced chemical reactions provided by the catalyst packing. Headwaters Resources, GRE's fly ash marketer, on average sees ammonia content in ash from 200-600 ppm for SNCR units and from 50-400 ppm for SCR units. *See Attachment 3 section.*

Dynegy's 1,800 MW Baldwin Energy Complex has 3 units burning Powder River Basin (PRB) coal. Two of the units have SCR installed, the third unit has no post-combustion NO_X control technology. Headwaters Resources, GRE's fly ash marketer, is also the ash marketer for the Baldwin Energy Complex. Headwaters only markets ash from the one pulverized coal unit that does not have either SCR or SNCR installed and therefore the ash sold does not contain ammonia. Please see attached letter from Herbert Moeckel of Headwaters Resources. *In Attachments 1 section.*

Currently there are no installations of SCR or SNCR burning North Dakota Fort Union lignite. As GRE does not have any data or experience with ammoniated ash we have asked our fly ash marketer, Headwaters Resources, to respond to Amy Platt's chemistry statement that alkaline ashes experience lower uptake of ammonia. Headwaters has extensive experience with ammoniated ash and they have observed higher ammonia odor emissions from a plant (East Lake Plant, OH) producing a higher alkaline ash. The mechanism for this higher evolution of ammonia has not been identified and is currently being investigated. *See email thread of December 29, 2009-in Attachment 2 section.* Without empirical evidence on uptake of ammonia on ash from ND lignite GRE cannot assume ammonia slippage rates or retention rates on fly ash. We have also presented the question about expected ammonia in ash for lignite units to Tony Facchiano, Sr. Program Manager at the Electric Power Research Institute (EPRI) and although they have done work for other types of coal they have not conducted research with ND lignite and would not be able to correlate the ammonia in ash with ammonia slip at this time.

As there are no data from Fort Union lignite on SNCR ammonia retention in ash we have provided testimony from GRE customers. As noted by our customers, ammonia-impregnated ash would have an economic impact not only on GRE but also to our marketers who sell the ash. *See enclosures from Lafarge and GCC of America in the Attachment 1 section.*

Fly Ash

Fly ash for use in concrete is classified in 3 classes: Class N – raw or calcined natural pozzolans that comply with ASTM C618-08; Class F - typically produced from burning anthracite or bituminous coal, but lignite also; Class C – typically produced from burning lignite's, but may also be produced from burning anthracite or bituminous coal as long as the total calcium contents are higher than 10% and the ash has some cementitious properties. CCS ash is classified as a Class F ash. Introduction of ammonia will not affect the class of our fly ash but will decrease the desirability and thus the marketability of our ash if the customer perceives a health risk or is able to procure the same material without the objectionable qualities.

The original investments made in the infrastructure for the marketing of fly ash was predicated on the fact that CCS is a mine mouth plant with a consistent coal source which is producing a high quality fly ash which is very desirable in the concrete market. The introduction of undesirable characteristics into the fly ash, such as an odor or inhalation risk, will force our concrete customers to pursue alternate marketers for their feedstock. *See testimonials from Headwaters Resouces, Lafarge, and GCC in the Attachments 1 section.*

Please contact me at 763-445-5208 regarding any questions or comments.

Sincerely,

GREAT RIVER ENERGY

Debra Nelson

Debra Nelson

c: Diane Stockdill
File

Attachment 1: Testimonials

HEADWATERS
RESOURCES

Adding Value to Energy

January 28, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Dear Mr. Christianson:

I am writing in regards to the Dynegy Midwest Generation – Baldwin Energy Complex located in Baldwin, Illinois. Headwaters Resources is the marketing company for all five Dynegy Midwest Generation plants located in Illinois.

The Baldwin Energy Complex is composed of three – 600 MW units, totaling 1800 MW. Units 1 and 2 are cyclone fired boilers and Unit 3 is a pulverized coal boiler, all three units are burning PRB coal. Units 1 and 2 are equipped / operating with an SCR and Unit 3 has neither a SCR or SNCR installed.

Headwaters Resources has mainly marketed the cyclone boiler fly ash produced from Units 1 and 2 into the cement industry as a raw feed ingredient since 1998. Since 2000, we were able to market approximately 17,000 tons of this material into "flowable fill" on a few mine subsidence projects in the East St. Louis, Illinois area. We have performed ammonia testing on the fly ash produced from Unit 1 and 2 utilizing the Headwaters SOP using dragger tubes. This material fluctuates between 35 and 125 ppm ammonia in the fly ash. The ammonia odor was noticeable when used on the flowable fill mixes which contained high volumes of fly ash per yard. The ammonia odor did not have an impact on our sales agreement with Buzzi Unicem, since they were using the material as a raw feed ingredient in the production of cement. Starting in July 2009 new mercury regulation forced the power stations in Illinois to use activated carbon injection to reduce mercury emissions. Units 1 and 2 did begin activated carbon injection in July 2009 at which time the material was no longer allowed to be used in the production of cement. At this time 100% of the fly ash material produced from these units is being disposed of in an on site impoundment. Dynegy is constructing SDA scrubbers which should be complete by 2013, at which time the injection point of the activated carbon will be moved allowing the use of the fly ash material in cement production. The fly ash produced from these two units is not suitable for use in concrete.

Unit 3 at the Baldwin Energy Complex was granted a temporary variance which did not force this unit to inject activated carbon until the SDA / Bag house is operational at the end of 2010. Headwaters Resources has marketed the ASTM C618 Class C fly ash produced from unit 3 into ready mix concrete, concrete paving, and soil stabilization since 1998.

Please feel free to contact me at 612-963-7093 regarding any questions or comments.

Respectfully

Herbert Moeckel
Technical Sales Representative
Headwaters Resources
P.O. Box 566
Osage Beach, MO 65065
P: 612-963-7093
F: 866-449-8130

GCC
of America

January 21, 2010

Mr. Al Christianson
GREnergy
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Al,

We would like to take this opportunity to express concern about GRE's potential injection of ammonia into the flue gas during coal burning operations as an effort to reduce NOx emissions. As a wholesale marketer and end-user of your fly ash from the Coal Creek facility in North Dakota, our concern surrounds the impact this process will have on the fly ash when used in concrete.

The ammonia in fly ash is not present as ammonia gas. Rather, it is in the fly ash as ammonium sulfate. Once in the high alkaline environment of concrete the ammonia is released. This becomes a problem because of the odor, especially in enclosed spaces such as residential basements. The smell of ammonia is objectionable and would potentially impact external fly ash sales for GCC of America and internal use in the concrete operations owned by GCC Ready Mix..

Our professional experience with this situation in the past had been limited to the senses, i.e. eye and nose irritation and unpleasant odor. The corrective action taken was at the expense of the concrete producer, causing those customers to do business elsewhere.

We value our relationship with your company and prefer to use your product because of its quality and performance. Please do not allow these attributes to be compromised. If you should have any questions, or if we may be of further assistance, please contact either of us our Denver offices at (303) 739-5900.

Sincerely,

Mark R. Lukkarila,
Technical Services Manager
GCC of America

Joseph E. Finnegan,
Regional Sale Manager
GCC of America

HEADWATERS
RESOURCES

Adding Value to Energy™

January 11, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Dear Mr. Christianson:

The Eastlake power plant in Eastlake, Ohio had a SNCR installed over 2 years ago. Prior to the installation the plant produced a high quality F-ash which was sold out every year during the construction season. The ammonia level was between 200-400 PPM after the installation which was when the problems started. Anything over 100 PPM seemed to be a noticeable at this plant.

We started shipping the material when it was in the 100-200 PPM range and the customers, batch plants and several contractors started calling with complaints especially in confined spaces such as buildings and basements. In one case a Ready Mix plant employee stuck his head in the back of the truck to add air entraining agent and it burned his eyes. He spent the night in the emergency room getting his eyes washed out not knowing it was the fly ash causing the ammonia smell.

We quit shipping anything over 100 PPM and business started dropping off; contractors did not want fly ash in their mixes. Since you're only checking a small amount of ammonia in the load it would test for less than 100 PPM but in some cases the Ready Mix producer still had problems which indicated the entire load was not less than 100 PPM. We shut down a block plant and the customer made us take the fly ash out of his silo and he quit buying fly ash from us.

Bill Newkirk

Bill Newkirk
Headwaters Resources
Technical Sales Rep
440-725-0088

2761 Port Neal Circle
Salix, IA 51052
P: 712.943.4049 F: 712.943.2876

LAFARGE
NORTH AMERICA

Cement

January 26, 2010

Mr. Al Christianson
Manager, North Dakota Business
Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503

Subject: Ammonia Injection in Fly Ash

Lafarge has used fly ash from power sources where SNCR ammonia injection units have been installed. We have found that when the ammonia levels exceed 40 parts per million in the fly ash that the consumer notices the ammonia and find it to be objectionable.

Lafarge is concerned that if ammonia injection units are installed at Great River Energy's Coal Creek Station it may cause the fly ash that is produced to be unmarketable. Lafarge currently purchases a large percentage of the fly ash that is produced at this station and would be placed at an economic disadvantage if we were no longer able to market this high quality ash to our ready mix customers.

This would cause our customers in turn to be at an economic disadvantage if they had to use fly ash from another source that is further away or use slag cement that perhaps would be more expensive than Coal Creek ash.

Roy V. Sander, Jr.

Roy Sander/General Manager

LAFARGE Dakota.
684 15th Ave. SW. PO Box 757, Valley City, ND 58072
Telephone: (701) 845-2421 Fax: (701) 845-1849 Toll Free: 1-800-533-8662

Attachment 2: Email Thread Headwater to GRE

From: Stockdill, Diane GRE-CC
Sent: Tuesday, December 29, 2009 3:38 PM
To: Nelson, Debra GRE-MG
Subject: FW: Where are we at?
Attachments: STI ammonia removal.pdf

Let's talk tomorrow

-----Original Message-----
From: Christianson, Al GRE-BI
Sent: Tuesday, December 29, 2009 3:35 PM
To: Stockdill, Diane GRE-CC
Subject: FW: Where are we at?

Fyi, they are working on it. al

Al Christianson
Manager, North Dakota Business Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503
701-250-2164 Direct
701-442-7664 Direct
701-220-4881 Cell
701-202-8964 Car
achristianson@grenergy.com
www.greatriverenergy.com

-----Original Message-----
From: Jerry Smith [mailto:jsmith@headwaters.com]
Sent: Tuesday, December 29, 2009 3:34 PM
To: Christianson, Al GRE-BI
Subject: FW: Where are we at?

Al: Attached is Bruce's response to your latest inquiry. It appears that we are still waiting on Mr. O'Conner (EPRI) to review our data on Sammis and East Lake ash. The attached brochure from STI may be helpful in the comparison of SNCRs and SCRs in regard to ammonia being introduced into the ash. I don't know if this is sufficient for your needs. If not, I suggest that we (Diane, you, and I) get on a conference call with Bruce to discuss what else we may be able to provide. Just let me know. Thanks.

From: Bruce Boggs
Sent: Tuesday, December 29, 2009 2:35 PM
To: Jerry Smith
Subject: RE: Where are we at?

Jerry,

There was no official document generated by EPRI to circulate on this issue. The curious finding that the more alkaline ashes had higher ammonia odor emissions was reported to EPRI but the reason for the finding was never identified. Dave O'Connor at EPRI will review our data showing the data on Sammis and East Lake comparisons.
The data from our East Lake plant with SNCR and higher alkaline ash should be available shortly to compare with the much lower levels of ammonia from an SNCR associated with low alkalinity ash at Sammis.

STI found it necessary to develop an ammonia removal/treatment system in addition to the carbon removal system they operate at several locations. I do not know if the Roxboro plant uses this system but I would point out that with the storage dome at Coal Creek, the ammonia levels that could accumulate would be extremely hazardous. A little know fact is that ammonia is an explosive gas at certain levels when it accumulates with air present. See attached STI brochure on ammonia removal. In that brochure they support the fact that SNCR units will introduce much more ammonia to the ash than SCRs but both can prevent ash from being used in the market.

Bruce

From: Jerry Smith
Sent: Tuesday, December 29, 2009 2:46 PM
To: Bruce Boggs
Subject: FW: Where are we at?

Bruce: Please see Al's and Diane's comments below. Have we heard anything from EPRI on this issue? Thanks.

From: Christianson, Al GRE-BI [AChristianson@GREnergy.com]
Sent: Tuesday, December 29, 2009 1:22 PM
To: Jerry Smith
Subject: FW: Where are we at?

Anything new, people want to know?

Al Christianson
Manager, North Dakota Business Development & Governmental Affairs
1611 East Century Avenue
Suite 200
Bismarck, ND 58503
701-250-2164 Direct
701-442-7664 Direct
701-220-4881 Cell
701-202-8964 Car
achristianson@grenergy.com<mailto:achristianson@grenergy.com>
www.greatriverenergy.com<http://www.greatriverenergy.com>

From: Stockdill, Diane GRE-CC
Sent: Tuesday, December 29, 2009 1:15 PM
To: Christianson, Al GRE-BI

Subject: Where are we at?

Where is Headwaters at on the SNCR justification documentation? I saw the waiting for EPRI response but when do they plan on having something to us?

Attachment 3: Headwaters information on SCR vs. SNCR

HEADWATERS

Adding Value to Energy™

Ammonia Contamination Levels

Air Pollution Control Process	NH_3 "Slip" ppm_v	NH_3 in Ash mg/kg
SCR	2 to 10	50 to 400
SNCR	5 to 20	200 to 600
SO_3 Control	10 to 20	300 to 600
ESP Conditioning	20 to 30	600 to 1200

Actual ammonia concentrations will depend on ammonia injection rates, coal type, sulfur content, and other operating parameters.

Environmental Groups

<u>Comment I</u>: The Clean Air Act and Federal Regulations Require NDDH to Abate Visibility Improvement.

A) The BART limits fail to reflect the best degree of continuous emission reduction achievable.

<u>Response</u>: The determination of BART is based on five factors: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts; 4) the remaining useful life of the source; and 5) the degree of visibility improvement. The NDDH considered all five factors in determining BART. BART is not necessarily the lowest possible emission rate or the emission rate (or technology) that achieves the maximum visibility improvement. All of the five factors must be considered. The NDDH is free to determine the weight and significance assigned to each factor (40 CFR 50, Appendix Y, Section IV.D Step 5). A response to specific comments on the BART analyses follows.

B) North Dakota should actively encourage other states and Canada to reduce emissions that impair visibility.

<u>Response</u>: The NDDH has consulted with other states as part of WRAP and the Northern Class I Areas workgroup. Significant emissions reductions will come from sources in each state involved in these groups. Negotiations with a foreign country are reserved to the U.S. Government. The NDDH is hopeful that the U.S. EPA and the U.S. State Department will pursue reductions at Canadian sources; however, the State of North Dakota has no control over these agencies.

Minnesota asked for additional reductions from EGUs in North Dakota. However, Minnesota's request was not based on the four factors that must be evaluated for reasonable progress. The NDDH suggested that Minnesota consider the fourth factor (cost of compliance) in their analysis, especially dollar per deciview improvement.

<u>Comment II</u>: NDDH's Draft BART Determinations are Flawed

II.A. NDDH purported to do a case-by-case evaluation of BART, it appears the case-by-case analysis were simply written to support the presumptive levels.

<u>Response</u>: Each EGU was evaluated considering the five factors. Since the original BART submittals, the NDDH has required 95% removal at Leland Olds Unit 1 and M.R. Young Unit 2 compared to the 90% removal proposed by the companies. At Stanton Station, GRE originally proposed sorbent injection. The NDDH has required a dry scrubber. The NDDH's evaluation of BART indicates these sources may exceed the 0.15 lb/10^6 Btu presumptive limit when higher sulfur coal is encountered. Instead of establishing a higher lb/10^6 Btu limit, the NDDH maintained the 0.15 lb/10^6 Btu presumptive limit but gave the sources the option of complying with the 95% reduction requirement.

None of these sources are subject to the BART Guidelines in 40 CFR 50, Appendix Y for SO_2. All the plants except Coal Creek Station have a nameplate capacity less than 750 MWe. Coal Creek Station is not subject to the BART Guidelines for SO_2 since its existing scrubbers are achieving greater than 50% removal efficiency. The NDDH considered the five statutory factors and determined BART appropriately.

II.A.I: NDDH Cannot Take into Account Projected Worst-Case Sulfur Content of Coal in Setting BART Limits.

Response: The BART Guideline states “The baseline emissions rate should represent a realistic depiction of **anticipated** [emphasis added] annual emissions for the source.” This statement clearly indicates future conditions should be utilized if it is different from historic conditions. EPA has allowed the use of the last 5 or 10 years for establishing the baseline (EPA – Additional Regional Haze Questions, August 3, 2006; Question 7). Because North Dakota lignite is extremely variable, using the highest 24-months out of the last 5 or 10 years may not give a realistic depiction of future conditions. Therefore, using the highest annual average sulfur content from a future period is consistent with the BART Guideline and EPA guidance.

In the case of Leland Olds, coal sulfur data was provided based on core sampling from the Freedom Mine (See Appendix B.2). The data shows an annual average sulfur content of 1.13% for 2019 and 1.12% for 2020. Since these are annual averages, they do not represent the maximum sulfur content that may be encountered during a given 30-day rolling average basis. For Coal Creek, the coal sulfur content selected was based on the 98th percentile of the coal sulfur data provided by GRE. The NDDH believes this is realistic for future emissions from Coal Creek.

For Milton R. Young Station, the average sulfur content from various core samples was used (see Table C.11, 4/18/07 Response to Comments). The maximum sulfur content is 5.5%.

For Unit 1 at the M.R. Young Station, the commenter is confusing the 2000-2004 average emission rate with the baseline emission rate. As noted earlier, the baseline emission rate, as suggested by EPA, is based on the maximum two years of emissions out of the last five years, not the entire five year period. Obviously, the five year average will be less than the maximum two year period. The commenter states that if actual emissions were reduced by the projected amount, Unit 1 would be emitting negative amounts of $SO_{2,}$ which is an impossibility. The commenter’s statement is based on the 2000-2004 average SO_2 emission rate. Use of a five year average is contrary to the BART guideline and other guidance which indicates a two year average should be used. Had the Department used the 2000-2004 average emission rate as the baseline, an emissions reduction of 95% would have indicated emissions (after the wet scrubber) of 1007 tpy, not a negative emission rate.

For Stanton, the maximum uncontrolled emission rates expected are 2.4 lb/10^6 for lignite and 1.60 lb/10^6 Btu for subbitimunous coal (See Appendix E of GRE’s analysis). In the NDDH BART analysis, 1.81 lb/10^6 Btu was used for lignite and 1.2 lb/10^6 Btu for subbituminous coal.

It is obvious the NDDH BART analysis did not use the maximum sulfur coal. The NDDH made a determination that the lower values would realistically depict future emissions.

II.A.2: The Proposed BART Limits Fail to Reflect the Degree of SO_2 Reduction Achievable with the BEST SO_2 Controls.

The commenter claims that 99% removal efficiency can be achieved using the Chiyoda CT-121 FGD or the Mitsubishi double contact flow scrubber.

Response: Regarding the Mitsubishi DCFS, literature by ADVATECH (copy attached to this response) for this scrubber indicates it can achieve very high sulfur removal efficiencies on high sulfur coal. However, tested performance on installed FGD systems indicate down to 90% removal efficiency for sulfur inlet concentrations of 1000 ppm or less. For North Dakota lignite, the inlet concentration is generally below 1000 ppm. The commenter also references two technical documents and a single sheet of information with no explanation of the source. These documents indicate high efficiencies at high inlet SO_2 concentrations (>1000 ppm), but low efficiencies (<95%) at most of the sources tested where the inlet sulfur concentration was less than 1000 ppm. The Department has proposed a wet scrubber that will achieve at least 95% removal under all inlet loadings. The NDDH is not convinced that this technology will provide any additional SO_2 removal.

The Chiyoda CT-121 FGS is a bubbling jet reactor which the commenters claim has achieved 99% SO_2 removal in Japan on coal fired boilers. The commenters provided several technical documents in an attempt to support their claim. The Black and Veatch brochure provides a list of installed and proposed facilities. The installed facilities have SO_2 removal efficiencies between 70-99%. However, for most of the facilities with lower inlet SO_2 concentrations, the removal efficiency is below 95%. This shows a wide range of efficiencies with little useful data.

The technical paper by Yasuhiko Shimoganci et.al. indicates an SO_2 removal efficiency of 99% at the Shinko-Kobe Power Plant in Japan. This paper provides no data on averaging times, the variability of the coal burned, or permittee emissions limits. It is also the NDDH's understanding that this plant has experienced operational problems with scaling of the FGD's sulfur gas fan which requires two days of maintenance every 2-3 months. The NDDH believes that it would be unreasonable to require this technology given the high outage time.

The commenters pointed out several facilities where this technology has been demonstrated or is to be deployed. This entire comment is nearly identical to one submitted on the Desert Rock BACT analysis. EPA investigated these claims and still rejected this technology as BACT (see attachments).

The commenter also refers to a "LADCO and MRPO" presentation that indicated the technologies could achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removal. Apparently, these figures were based on 2.5% sulfur which is twice as high as that proposed for any of the North Dakota BART sources. More detailed information would be required from the commenter to assess the cost for this lower sulfur coal.

As indicated earlier, this comment is nearly identical to one submitted for the Desert Rock Power Plant BACT determination. EPA's response to this comment for Desert Rock is attached to this response. The NDDH agrees with EPA's BACT determination which rejected this technology. The NDDH does not consider the Chiyoda CT-121 scrubber or the Mitsubishi DCFS to be BART.

II.A.4 a, b, c: The Proposed SO_2 BART Limits Should be Expressed Multiple Ways.

The commenter indicates that 98-99% removal efficiency should be required based on the technology discussed in Comment II.A.2. The NDDH believes this removal efficiency is not feasible on a continuous basis for lower sulfur lignite (<1.5% sulfur). New wet scrubbers generally achieve SO_2 removal efficiencies of 95% (Institute of Clean Air Companies, 2008; Federal Register Vol. 70, No. 28, P.9715). EPA (Air Pollution Control Technology Fact Sheet; EPA-451/F-03-034) indicates "Chlorine content improves SO_2 removal…" North Dakota lignite has some of the lowest chlorine levels of all the U.S. coals. Based on the low chlorine content and lower sulfur content, the NDDH believes that 95% is a reasonable removal efficiency for a scrubber to meet on a continuous long-term basis which includes startups, shutdowns and malfunctions.

The commenter also states the proposed BART limit of 0.15 $lb/10^6$ Btu should be lowered based on <u>current</u> coal sulfur content. The commenter does not acknowledge that higher sulfur coal will be burned in the future. The future coal sulfur content is based on actual core samples from future mining areas. As explained in the response to Comment II.A.1, the baseline for determining the BART limit is based on the <u>anticipated</u> emissions that are expected to occur. The NDDH considers the core samples of future mined coal to be strong evidence of anticipated emissions. Based on 95% removal, the M.R. Young plant would have an SO_2 emission rate of 0.60 $lb/10^6$ Btu when the maximum sulfur coal of 5.6% is burned. Using one standard deviation from the average sulfur content would yield a controlled emission rate of 0.17 $lb/10^6$ Btu.

At the Leland Olds Station, a maximum 30-day rolling average of 0.19 $lb/10^6$ Btu would be expected based on an <u>annual average</u> sulfur content of 1.13% and 95% reduction. At Coal Creek, a 30-day rolling average SO_2 emission rate of 0.18 $lb/10^6$ Btu would be expected based on an annual average sulfur content of 1.1%. The NDDH stands by its decision to limit emissions to 0.15 $lb/10^6$ Btu.

The commenter also wants a mass per unit of time emission limit included in the BART Permit to Construct. The NDDH contacted EPA Region 8 earlier in the BART process regarding this issue. In a November 21, 2005 email response from Laurel Dygowski of EPA Region 8, it was stated "We think a 24-hour limit is unnecessary and may not be of much value." Given the small amount of emissions coming from these sources after controls, a mass per unit of time emission rate will be easily calculated with very good accuracy.

The NDDH stands by its decision not to include a mass per unit of time emission rate.

II.A.4.d: Comments Regarding the Stanton Station Unit 1 SO_2 Emission Limits

The commenter states that "there is no valid justification for NDDH to increase the derived emission rate reflective of 90% control by 33%". The commenter refers to the 33% adjustment factor used by the Department to adjust from an annual average emission rate to a 30-day rolling average emission rate.

It is common practice to establish higher short-term limits to allow for short-term emissions variability inherent to facility operations. The EPA RACT/BACT/LAER Clearinghouse contains numerous examples of short-term BACT limits which are higher than longer-term BACT limits. For example, a permit issued to Omaha Public Power District (RBLC ID NE-0031) on March 9, 2005 establishes a 3-hour average SO_2 BACT emission limit of 0.48 lb/MMBtu compared to the 24-hour SO_2 BACT limit of 0.163 lb/MMBtu and a 30-day rolling average SO_2 BACT limit of 0.095 lb/MMBtu. A permit issued to Wellington Development / Greene Energy (RBLC ID PA-0248) on July 8, 2005 establishes a 3-hour average SO_2 BACT limit of 0.234 lb/MMBtu and a 30-day rolling average SO_2 BACT limit of 0.156 lb/MMBtu. A permit issued to River Hill Power Company (RBLC ID PA-0249) on July 21, 2005 establishes a 24-hour average SO_2 BACT limit of 0.274 lb/MMBtu and a 30-day rolling average SO_2 BACT limit of 0.20 lb/MMBtu. Two examples where annual and 30-day rolling average BACT limits were established include permits issued to Associated Electric Cooperative (RBLC ID MO-0077) and Western Farmers Electric Cooperative (RBLC ID OK-0118). The permit issued on February 22, 2008 to Associated Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.065 lb/MMBtu and an annual average NO_x limit of 0.05 lb/MMBtu. The permit issued on February 9, 2007 to Western Farmers Electric Cooperative establishes a 30-day rolling average NO_x limit of 0.07 lb/MMBtu and an annual average NO_x limit of 0.05 lb/MMBtu. In addition, a permit issued by EPA on July 31, 2008 for the Desert Rock facility establishes a 30-day rolling average NO_x limit of 0.05 lb/MMBtu and an annual average NO_x limit of 0.0385 lb/MMBtu. Clearly, it is common practice to establish short-term BACT limits which are higher than longer-term BACT limits.

The Department has reliable data based upon actual facilities operating in North Dakota to support the use of the 33% adjustment factor. In addition, adjustment factors (to adjust from an annual average limit to a 30-day rolling average limit) calculated from Associated Electric Cooperative, Western Farmers Electric Cooperative and Desert Rock limits are approximately 30%, 40% and 30%, respectively. These adjustment factors are very close to the adjustment factor of 33% used by the Department. Since the Department has reliable data to support the use of the 33% adjustment factor and no data has been submitted indicating that the factor is not appropriate, the Department maintains the position that the 33% adjustment factor is appropriate.

The commenter states that spray dryers can achieve greater than 90% SO_2 removal and references permits issued for the Newmont Nevada TS, White Pine, Toquop Energy and Dry Fork facilities.

The Newmont Nevada TS power plant construction permit requires a 95% control efficiency when combusting coal with a sulfur content equal to or greater than 0.45% and a 91% control efficiency when combusting coal with a sulfur less than 0.45%. Based upon this permit, it is possible for the facility to operate with lower sulfur coal, maintain a control efficiency of 91% and meet the requirements of the permit. The Department does not consider a 91% control efficiency to be significantly different than a 90% control efficiency and the commenter provides no data indicating that a control efficiency greater than the 91% requirement has been routinely attained at the Newmont Nevada facility. The Department conducted the BART analysis for Stanton Station #1 when combusting PRB coal assuming an uncontrolled emission rate of 1.2 lb/MM Btu (on an annual average basis) and a control efficiency of 90%. If slightly higher sulfur coal is burned at Stanton Station #1, then the facility will need to attain a slightly higher removal efficiency than 90% to maintain compliance with the emission limit. Although a slightly higher control efficiency may be attainable on a short-term basis, the Department maintains the position that a standard spray dryer is routinely capable of a 90% SO_2 control efficiency, especially when periods of startup, shutdown and malfunction are included. The Department considered other control technologies (wet scrubber, circulating dry scrubber) with higher control efficiencies than 90% in the BART analysis and eliminated these technologies based upon cost and other environmental considerations.

The commenter references a "draft Toquop permit" as exhibit 22. However, as submitted, both exhibit 21 and 22 are the Desert Rock permit, so it appears the Toquop permit was excluded from the exhibits. The Department has reviewed the draft permit for the Toquop Energy, LLC facility on the Nevada Division of Environmental Protection web site and has found that the control technology proposed for the Toquop facility is a wet scrubber, not a spray dryer. Since the Toquop facility will be employing a wet scrubber, the draft permit for the facility does not support the commenter's position regarding the control efficiency of a spray dryer.

The commenter indicates that the White Pine power plant has not been constructed and is "indefinitely postponed", so this provides no evidence that a spray dryer can routinely attain SO_2 control efficiencies greater than 90%.

The commenter references the Dry Fork Station as evidence that a spray dryer can attain greater than 90% SO_2 control efficiency. However, the control technology to be used at the Dry Fork Station is a circulating dry scrubber, not a spray dryer. The Department did consider a circulating dry scrubber (at 93% SO_2 control efficiency) in the BART analysis for Stanton Station #1 and determined that the incremental cost of a circulating dry scrubber (compared to a spray dryer) is excessive.

The commenter argues that spray dryers can achieve greater than 90% SO_2 removal and presented four facilities (Toquop Energy, Dry Fork, White Pine and Newmont Nevada) to support this argument. The Toquop Energy and Dry Fork facilities are not proposing to use a spray dryer to control SO_2 emissions. The White Pine facility does not appear to have been issued a permit. The only facility which is employing a spray dryer and which has operated is the Newmont Nevada facility. However, as indicated above, the Department is not aware of any data from this facility demonstrating that a standard spray dryer can routinely attain SO_2 control efficiencies greater than 90%.

Based upon the above, the Department maintains the position that a standard spray dryer can be expected to routinely attain an SO_2 control efficiency of 90%.

The commenter states that the Department eliminated a wet scrubber from consideration as BART based only on the small amount of visibility improvement. The commenter argues that, since the cost of a wet scrubber is not prohibitive, the Department must require the use of a wet scrubber as BART at Stanton Station #1.

The BART determination for Stanton Station #1 clearly states that the Department chose a spray dryer as BART as opposed to a wet scrubber based upon both the additional environmental impacts and the small visibility improvement of a wet scrubber as compared to a spray dryer. The additional environmental impacts of a wet scrubber were outlined in the BART determination as follows:

- A wet scrubber is estimated by GRE to use as much as 20% more water or approximately 15 million gallons per year of additional water.
- It is assumed that a wet scrubber system will require additional on-site ponding. GRE has identified two potential areas on site that could be used for the additional ponding. The areas include the existing ash pile, which would have to be excavated and moved, or the abandoned ash disposal area adjacent to the river, which reportedly has geotechnical deficiencies.
- Dry scrubbers are purported to achieve a higher mercury control efficiency on lignite and PRB as compared to a wet scrubber. In addition, future mercury control requirements could result in high concentrations of mercury in the ponds and prove problematic to discharge.

Considering the additional environmental impacts and the fact that a wet scrubber will result in a small visibility improvement beyond the control achieved by a spray dryer, the Department maintains the position that BART for SO_2 at Stanton Station #1 should be established as a spray dryer with a fabric filter.

The commenter states that a wet scrubber can attain SO_2 removal efficiencies of 98-99%. See responses to comments for Sections II.A.4.a, b and c.

The commenter states that the Department should establish both a numerical emission limit and a minimum control efficiency for SO_2. The BART guidelines list the presumptive levels in units of lb/million Btu or a percent reduction. Given that the presumptive levels are listed in units of lb/million Btu or a percent reduction, the Department does not believe it is appropriate to establish emission limits on a lb/million Btu and percent reduction basis.

II.A.5: There Are Other Benefits to NDDH Requiring Stringent SO_2 BART Limits That NDDH Must Take Into Account.

The commenter indicated that the NDDH should control SO_2 to low levels to facilitate the capture of CO_2. There are currently no regulations that require CO_2 capture. There are only a few technologies that are in various stages of development from bench scale to testing at full scale. The NDDH cannot consider what may happen in the future regarding CO_2 capture. A cap and trade program may make purchasing CO_2 credits (allowances) more economically feasible than capture. New technologies may be developed which do not require low SO_2 concentrations.

The NDDH believes CO_2 capture is currently only in its infancy and future regulatory requirements are too uncertain at this time to be considered in the current BART determinations.

The commenter also indicates that $PM_{2.5}$ concentrations will also be lowered with lower SO_2 emissions and this should be considered in the BART determination. The commenter's statement is true that lower SO_2 emissions will probably lead to lower $PM_{2.5}$ concentrations. The entire state of North Dakota is in compliance with current NAAQS for $PM_{2.5}$. BART requirements will reduce SO_2 emissions by nearly 100,000 tons per year. This should reduce $PM_{2.5}$ concentrations significantly in affected areas. The small emissions reductions going from 95% SO_2 reductions to 98-99% reduction will have little effect on ambient $PM_{2.5}$ concentrations due to dispersion of the plumes. The NDDH considers this issue as insignificant in the BART determination process.

II.B.1: High Dust SCR (HDSCR) is Technically Feasible.

The commenter claims that high dust SCR is technically feasible for North Dakota lignite. The commenter expressed comments about several issues the NDDH discussed in the technical feasibility analysis. These include: 1) The variability of fuel composition; 2) Results for the Coyote Pilot testing; 3) Sodium in the ash; 4) Temperature variations, 5) Catalyst erosion and; 6) the Lack of vendor guarantees.

Response: The BART Guideline states "Where you conclude that a control option identified in Step 1 is technically infeasible, you should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emissions unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are irresolvable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)." The commenter did not supply any analyses of the flue gas from North Dakota lignite combustion to demonstrate that HDSCR is technically feasible. The commenter did address sodium in the flue gas by stating "At least one of the catalyst vender noted that sodium is not a poison to a catalyst at SCR operating temperatures." The commenter went on to say that proper operation will prevent catalyst deactivation and that if any condensation occurs, it can be mitigated by washing. The NDDH has concluded that moisture, or condensation, is not necessary to poison the catalyst. Zheng et.al (2008) concluded that the submicron aerosols of soluble potassium and sodium are transported into the catalyst pores by diffusion (i.e. surface diffusion). Several pilot and full scale tests have found rapid deactivation of SCR catalyst from potassium and sodium aerosols from biomass combustion when the catalyst was at normal operating temperatures. Haldor Topsoe (Crespi et.a.) in their paper, *The Influence of Biomass Burning in the Design on an SCR Installation* states "Submicron aerosols adhere to the catalyst surface or diffuse into the macro pores. The aerosols cannot diffuse into the clusters as primary TiO_2 support particles, which appear as islands at the catalyst surface. However, the alkalis are very mobile and are readily transported by surface diffusion into the clusters and react with the active sites. The reaction is not reversible:" The NDDH agrees that condensation will greatly enhance catalyst deactivation; however, severe catalyst deactivation from Na and K aerosols does occur at biomass boilers without condensation of moisture occurring.

Catalyst washing may help regenerate a catalyst that has been coated or the pores plugged. However, as Haldor Topsoe notes, when soluble Na or K reacts with the active sites, the reaction cannot be reversed by washing.

The commenter specifically addressed a) the variability of fuel composition, b) the Coyote Pilot testing, c) sodium, d) temperature variations, e) catalyst erosion, and f) lack of vendor guarantees.

a) Variability – The commenter indicated that the variability of North Dakota lignite was not an issue and that it can be overcome by proper design.

Response: The analyses that were conducted for the technical feasibility determination used an average ash content and average sodium and potassium content of that ash. Data supplied by the companies indicates that the ash content can be twice as high as the average and the Na_2O content can be 3-4 times the average (see Minnkota's 4/18/07 response to comments). The analyses indicate that average coal constituents will rapidly deactivate an SCR catalyst. If the amount of sodium is increased by a factor of 6-8, even more rapid catalyst deactivation is expected. The commenter has provided no evidence indicating that coals used at power plants that have HDSCR have such a high variability in the catalyst poisoning agents.

b) Results of the Coyote Pilot Testing – The commenter dismissed the results of the Coyote testing indicating that any conclusions from the testing should be rejected.

Response: The NDDH made only one conclusion from the testing. That is, there is a difference between subbituminous coal and North Dakota lignite when it comes to the design and operation of an SCR system. The Coyote testing showed much more severe plugging problems than at the Baldwin Station. This indicates the design may require a different pitch and a much larger reactor. As Sargent and Lundy (PowerPoint Presentation 5/2007) has noted, "Some important unanswered questions pose significant risk for an SCR design engineer."

- An unknown catalyst deactivation rate will prevent:
  - Optimum selection of a catalyst design
  - Selection of an appropriate reactor size

S&L also indicated "there are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance." The NDDH has concluded that pilot scale testing would be required before HDSCR could be deemed technically feasible. The BART sources are not required to do that testing.

c) Sodium: The commenter believes sodium is not an issue for SCR deactivation unless condensed water is available in the SCR reactor.

Response: See Response to Comment II.B.1

d) Temperature Variations – The commenter claims that high temperature variations should not preclude HDSCR from being technically feasible.

Response: High temperatures entering an SCR catalyst can quickly deactivate a catalyst through sintering. In order to determine if this problem can be overcome, expensive and lengthy engineering analysis will be required. The BART Guideline states "Alternatively, a demonstration of technical infeasibility may involve a showing that there are unreasonable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability and adverse side effects on the rest of the facility)." Until the engineering studies are completed, temperature swings must be a consideration in determining technical feasibility.

e) Catalyst Erosion – The commenter contends that ash erosion is not a concern that has been substantiated.

Response: Catalyst erosion is a significant concern. Ash from North Dakota lignite has different abrasive qualities from other coals. The experience from other coals may not be applicable to North Dakota lignite.

f) Lack of Vendor Guarantees – The commenter claims that both CERAM and Haldor Topsoe have stated that they would offer guarantees for HDSCR.

Response: The commenter is correct that CERAM and Haldor Topsoe initially indicated they would offer guarantees. However, Minnkota has approached these same two companies regarding a guarantee for LDSCR and TESCR which should be less susceptible to catalyst poisoning than HDSCR. Both companies have refused to offer a guarantee for LDSCR or TESCR without pilot testing first (see NO_x Best Available Control Technology Analysis Study – Supplemental Report, November 2009). If these companies will not offer a guarantee for LDSCR or TESCR, it is expected they would not offer one for HDSCR.

The NDDH stands by its determination that HDSCR is not technically feasible for North Dakota lignite at this time.

II.B.2: TESCR and LDSCR are Cost Effective

The commenter indicates both TESCR and LDSCR are cost effective. This comment is based on a few BACT determinations and the National Park Service's database of BART determinations (preliminary and final by the States) that have not been promulgated in an EPA approved SIP. BART determinations are not the same as BACT determinations. For BART determinations, the amount of visibility improvement must be considered. The Department's analysis of LDSCR and TESCR indicate cost effectiveness values above $3,581 per ton and incremental costs at $5,978/ton or greater. The comparison to the NPS database indicated that costs are as high or higher than anything approved for BART. In addition, the amount of visibility improvement is very low (≤ 0.02 deciviews on the most impaired days). The high cost and miniscule visibility improvement dictates that SCR is not BART.

The commenter also indicated there was a lack of transparency regarding the methodology for developing the costs estimates. The cost estimates were developed by engineering consultants who are experienced with SCR design and installation. The estimate provides as much detail as the EPA Air Pollution Control Cost Manual which is recommended by the BART Guideline. The NDDH believes the cost estimates are within the ± 30% accuracy of the Control Cost Manual. Given the very small visibility improvement, the costs are of less importance. The NDDH stands by the estimated costs.

II.B.3: Specific Comments on Each NO_x BART Analysis

A) Lelands Olds Unit 1 - The commenter believes LDSCR is cost effective.

Response: The cost effectiveness of LDSCR ranges from $7,849/ton to $11,313/ton with an incremental cost of $12,489/ton. This is 6-9 times more than the EPA estimated cost of the controls necessary to meet the BART presumptive limits for lignite fired dry bottom wall-fired units. The cost is nearly twice that of most recent BACT determinations for NO_x. The State of Wyoming recently rejected a lower NO_x emission rate (0.043 lb/10^6 Btu) for the Dry Fork plant based on a cost effectiveness of $1,751/ton and an incremental cost of $10,300/ton. The NDDH stands by its determination that LDSCR and TESCR are not cost effective for Leland Olds Unit 1. The NDDH has required Basin Electric to meet an NO_x emission limit that is below the presumptive BART limit.

B) Leland Olds Unit 2 – The commenter believes HDSCR is technically feasible and LDSCR was rejected based on erroneous cost criteria.

Response: Regarding HDSCR technical feasibility, see Response to Comment II.B.1.

The commenter has provided no technical analysis or evidence to show that the cost estimate is erroneous. The NDDH stands by the cost estimate for LDSCR and TESCR.

C) Coal Creek Units 1 and 2 – The commenter states that HDSCR was improperly rejected and the use of 80% control for SCR biased the cost effectiveness to the high side.

Response: Regarding HDSCR technical feasibility, see Response to Comment II.B.1.

The Department has reviewed the EPA Air Pollution Control Cost Manual which states "In practice, SCR systems operate at efficiencies in the range of 70% to 90%. EPA's Air Pollution Control Technology Fact sheet for the selective catalytic reduction (EPA-452F-03-032) states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%." The Oregon DEQ hired Eastern Research Group, Inc. (ERG) to review the BART analysis for the PGE Boardman Plant. In their review, ERG stated "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR of the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The NDDH believes the use of 80% is a reasonable choice for a source that must meet a BART emission limit on a long-term continuous basis. In the ANPR for the Four Corners Power Plant (Federal Register 8/28/09), EPA states "APS estimated that SCR could achieve NO_x control of approximately 90% or greater from the baseline emissions. For new facilities, 90% or greater reduction in NO_x from the SCR can be reasonably expected. See May 2009 White Paper on SCR from Institute of Clean Air Companies. For SCR retrofits on an existing coal-fired power plant, Arizona Department of Environmental Quality (ADEQ) determined that 75% control from SCR (following upstream reductions by LNB) was appropriate for the Coronado Generating Station in Arizona. Based on this data, EPA has determined that an 80% control efficiency for SCR alone, rather than the 90% control assumed by APS, is appropriate."

The Department believes 80% is a reasonable estimate that allows the source to comply with the expected emission limit on a continuous basis.

D) Stanton Station Unit 1 – The commenter believes HDSCR was rejected improperly and a cost effectiveness of $6,475/ton is reasonable.

Response: Regarding the technical feasibility of HDSCR, see Response to Comment II.B.1

Regarding cost effectiveness, see Response to Comment II.B.3(a). The estimated cost effectiveness of $6,475/ton when burning lignite is five times the amount EPA found was cost effective for the presumptive limits for wall-fired lignite units. In addition, the incremental cost when burning lignite is $10,032/ton. This unit will meet the presumptive BART limits for both lignite and subbituminous coal.

E) M.R. Young Station Units 1 and 2 – The commenter states that the NDDH has done no more than is required by law and rolled it into the BART analysis. The commenter also states that HDSCR was rejected erroneously and the cost effectiveness of LDSCR and TESCR are reasonable.

Response: Although the Consent Decree requires the level of emissions that are proposed for BART, the NDDH conducted a BART analysis in accordance with the Five Step BART process. After considering the five factors, SCR was rejected as BART.

Regarding the technical feasibility of HDSCR, see the Response to Comment II.B.1.

With respect to cost effectiveness, see the Response to Comment II.B.3.A. The cost effectiveness of LDSCR and TESCR is three to five times the cost EPA had estimated for cyclone boilers to meet the BART presumptive emission rate. The Department believes these costs are excessive in comparison to EPA's analysis and are very high when compared to recent BACT determinations. However, the NDDH also considered the amount of visibility improvement and the other three factors in making its BART determination. The amount of visibility improvement (≤0.02 deciviews on the most impaired days) when compared to the next most efficient technology is trivial. The NDDH stands by its BART determination.

Comment III: NDDH Has Failed to Include Other Emission Reduction Requirements as Part of Its Long-Term Strategy to Meet Reasonable Progress Requirements which must be Designed to Meet the Goal of Natural Visibility Conditions by 2064.

The commenter indicated the following:

A) BART sources should have been reevaluated under the reasonable progress section of the SIP.
B) North Dakota is not doing its fair share to reduce visibility improvement.
C) SO_2 controls that achieve 98-99% efficiency should have been considered.
D) Costs alone should not eliminate controls on sources under BART.
E) The SIP does not go far enough to ensure that natural visibility conditions are achieved by 2064.

Response:

A) EPA has published guidance for determining Reasonable Progress for regional haze – Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, June 1, 2007. This document states "Also, as noted in Section 4.2, it is not necessary for you to reassess the reasonable progress factors for sources subject to BART for which you have already completed a BART analysis." Section 4.2 states "Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period." In Section 9.5.1, the NDDH discussed the elimination of the BART sources from the reasonable progress goals analyses. The NDDH concluded that all controls that were reasonable were included as BART. The NDDH stands by this decision.

B) In the North Dakota Class I areas, visibility improvement is mostly due to sulfates and nitrates. The emission control requirements under the SIP will reduce SO_2 emissions by 60% and NO_x emissions by more than 25%. The uniform rate of progress goal for this planning period would only require a 23% (14 years – 60 years) reduction in visibility impairment.

   The following table shows the expected change in emissions by 2018 from surrounding States and Canada.

Projected Change in Emissions 2002-2018 (%)					
	South Dakota	**Montana**	**Minnesota**	**Canada**	**North Dakota**
SO_2	-35.7	-11.8	-28.8	-6.8	-60.0
NO_x	-17.9	-26.0	-39.4	-0.8	-25.3
OC	-6.1	-3.3	-5.3	22.7	-19.4
EC	-51.1	-16.6	-28.9	75.2	-52.3
PMF	2.2	7.5	-1.3	34.8	2.0
PMC	5.2	8.8	-4.4	33.8	3.5
NH_3	0.3	1.2	33.9	-31.9	-0.3
VOC	-0.5	-0.6	2.9	-1.2	1.1
CO	-17.0	-15.9	-20.8	-11.7	-27.4

This table clearly shows that North Dakota is doing more to reduce the primary visibility impairing pollutants (SO_2 and NO_x) than the surrounding states. In addition, North Dakota is exceeding the 23% reduction calculated from the URP for this planning period for both SO_2 and NO_x. The NDDH believes that North Dakota is doing more than its fair share to address emissions reductions to reduce regional haze.

C) See Response to Comment II.A.2

D) The BART determinations were based on the five statutory factors which include: 1) cost of compliance, 2) the energy and non-air quality environmental impacts of compliance, 3) any existing air pollution control equipment in use at the source, 4) the remaining useful life of the source, and 5) the amount of visibility improvement expected from the use of the control technology. The NDDH evaluated all five factors and discussed them in the BART determinations. Cost alone was not the single factor that determined BART. For Coal Creek and Stanton Station, non-air environmental issues were a significant issue in the BART determination for NO_x and SO_2 respectively. Visibility improvement was a significant factor for NO_x at Leland Olds Station and M.R. Young Station. Existing control equipment was an important factor for determining BART for particulate matter at each BART source. The BART determinations were not made on cost alone.

Some technologies were obviously not cost effective. EPA addressed this issue in the preamble to the BART Guideline: "The interpretation of the requirements of the regional haze program reflected in the discussion above does not necessitate costly and time-consuming analyses. Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible," (F.R. Vol. 70, No. 128, p.39116). The NDDH has taken this streamlined approach where the cost is obviously excessive.

E) The NDDH has included all reasonable control reduction measures in the SIP. The NDDH has shown that if all SO_2 and NO_x emissions in the State were eliminated, the uniform rate of progress for the first planning period could not be met (see Section 8.6.3.3 of SIP). This is because of the huge influence out-of-state sources have on the North Dakota Class I areas, especially Canadian sources. As noted in the SIP (Section 9.7), achieving natural conditions by 2064 is impossible without a new, zero emissions energy source. The Regional Haze SIP demonstrates that North Dakota is doing its fair share to secure reductions that will reduce visibility impairment.

Comment IV: North Dakota Must Also Propose Short-Term Average Emission Limits on SO_2 Emissions in Order to Ensure Protection of the SO_2 Increments of the State's Class I Areas.

The commenter believes that SO_2 increment is exceeded in the Class I areas of North Dakota and that short-term emission limits for SO_2 must be included in the BART permits to protect the increment.

Response: Modeling conducted by the Department (see Documents Relating to a Memorandum of Understanding between the State of North Dakota and the U.S. Environmental Protection Agency Regarding Computer Modeling Protocol for the State's PSD Program) indicates the increment for SO_2 is not exceeded. The NDDH stands by this analysis.

The SIP will reduce SO_2 emissions by nearly 106,000 tons by 2018. This will make actual emissions less than the baseline emissions. Therefore, SO_2 reductions in North Dakota will actually expand the amount of increment available for other new sources. There will be no question that emissions from sources in North Dakota (or surrounding states) do not cause concentrations of sulfur dioxide that exceed the increments.

Comment V: Other General Comments

1) Technical support is necessary to demonstrate that the Painted Canyon Improve Monitor is representative of Elkhorn Ranch Unit and the North Unit of TRNP.

2) The details of the baseline visibility calculations need to be included in the SIP.

3) The analysis of MDU Heskett cannot be putoff and must be included in the Regional Haze SIP.

Response:

1) The choice of the IMPROVE THRO1 monitor site was made by the federal agencies in 1999 when the IMPROVE network was expanded to 108 sites regionally representative of the 156 mandatory federal Class I areas. The existing monitoring site at the Painted

Canyon Overlook in the South Unit was selected to provide regionally representative coverage and data for the three units of Theodore Roosevelt National Park. Site selection followed the criteria in the Improve Particulate Monitoring Network Procedures For Site Selection, February 24, 1999, prepared by the Crocker Nuclear Laboratory of the University of California Davis, the IMPROVE contractor. The criteria included requirements that all areas represented by the site should be within 100 km of a current or potential site, whose elevation lies between the highest and lowest elevations of all areas, with a permitted variance of 100 feet or 10 percent. The site must avoid small valleys, should also avoid local pollution sources or areas with unusual meteorology and avoid nearby obstacles that could affect sample collection. The site also must be accessible for weekly sample change in all but the most severe weather. It was desirable to have existing electrical power available. The existing Painted Canyon Overlook monitoring site met all the criteria in the Procedures for Site Selection including being approximately 80 km away from the northern boundary of the North Unit and 45 km away from the Elkhorn Ranch Unit. The University of California Davis maintains the photographic and written documentation of the THRO1 site.

2) The baseline visibility calculations are taken from the WRAP TSS website. This is noted on p.34 of the SIP. The documentation for the calculations can be found in the 2006 Report for the Western Regional Air Partnership (WRAP) Regional Modeling Center (RMC) on pages 31-32. These pages will be included in an appendix to the SIP.

3) The analysis of the Heskett Station will be included in the Regional Haze SIP as a supplement. The NDDH's analysis demonstrates that the Heskett Station is exempt from BART requirements and EPA has indicated that they agree with the Department's determination. The supplement regarding the Heskett Station will be included in the SIP following proper adoption procedures.

Attachments

1. Environmental Groups' Complete Comments

2. EPA's Response on SO_2 Control Technology for the Desert Rock Power Plant BART Determination

3. ADVATECH Brochure

4. EPA response regarding Heskett Station BART Applicability

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January 8, 2010

Via email:

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RE: Comments on North Dakota's Regional Haze State Implementation Plan

Dear Mr. O'Clair:

On behalf of Dakota Resource Council, National Parks Conservation Association, Dakota Resource Council, Friends of the Boundary Waters Wilderness, Plains Justice, Dakotah Chapter of the Sierra Club, South Dakota Chapter of the Sierra Club, and Voyageurs National Park Association, we respectfully submit the following comments on the Draft North Dakota Regional Haze (RH) State Implementation Plan (SIP). Our organizations represent hundreds of North Dakotans and thousands of people throughout the nation that care deeply about protecting the air quality in our national parks and wilderness areas in the Dakotas and Midwest. We hope and strongly encourage the North Dakota Department of Health (NDDH) to revise its SIP by requiring further reductions in haze causing pollutants and otherwise advancing measures that will improve regional visibility.

For the reason stated herein, North Dakota's regional haze plan is both legally and technically deficient. The regional haze plan fails to require sufficient reductions in visibility impairing pollutants from its major polluting sources and fails to provide a long term strategy that would meet reasonable progress goals. As addressed below, the State can and must achieve much greater emission reductions in haze causing pollution with available control technologies and/or by imposing more stringent emission limits reflective of the best level of continuous emission reduction in its Best Available Retrofit Technology (BART) determinations. In addition, the long-term strategy must ensure appropriate BART requirements and other measures, including consideration of source retirement and replacement, to improve visibility in

North Dakota and other downwind states' Class I areas to ensure that the SIP will meet its share of the emission reductions needed to meet the reasonable progress goals for the area.

Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances, color and geologic formation. While some haze causing particles result from natural processes, most result from anthropogenic sources of pollution. Haze forming pollutants including sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), volatile organic compounds (VOCs), and ammonia (NH_3) contribute directly to haze or form haze after breaking down in the atmosphere. These air pollutants contribute to the deterioration of air quality and reduced visibility in our nation's national parks and wildlife refuges. Visibility impairment is measured in deciviews, which is understood as the perceptible change in visibility. The higher the deciview value is, the worse the impairment.

Through the Clean Air Act (CAA), Congress established "as a national goal the prevention of any future, and remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. §7491(a)(1). In order to meet this goal, a State is required to design an implementation plan to reduce and ultimately eliminate haze from air pollution sources within its borders that may reasonably be anticipated to cause or contribute to visibility impairment for any protected area located within or beyond that State's boundaries. In creating and implementing the plan the State has an unparalleled opportunity to protect and restore regional air quality by curbing visibility impairing emissions from some of its oldest and most polluting facilities.

Each SIP must provide "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal." 42 U.S.C. § 7491(b)(2). Two of the most critical features of a SIP are requirements for (1) the installation of BART for delineated major stationary sources of pollution and (2) a long-term strategy for making reasonable progress towards the national visibility goal. 42 U.S.C. § 7491(b)(2)(A) & (B).

There are two Class I areas in North Dakota—Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area. Other Class I areas impacted by North Dakota sources of air pollution include: Badlands National Park and Wind Cave National Park in South Dakota, Medicine Lake National Wildlife Refuge Wilderness Area and U.L. Bend National Wildlife Refuge Wilderness Area in Montana, Boundary Waters Canoe Area Wilderness Area and Voyageurs National Park in Minnesota, and Isle Royale National Park and Seney National Wildlife Refuge Wilderness Area in Michigan. These Class I areas preserve the region's inspiring landscapes, rare geologic formations, breathtaking water country, and diverse wildlife and vegetation. They also serve as living museums of our nation's history. Visitors from across the nation and globe are drawn to these lands and their tourist dollars benefit state and local economies.

National parks and wilderness areas are of great natural and cultural value and also engines for sustainable local capital. For example, in 2008, National Park Service units received over 274 million visits accounting for over $2.5 billion in revenue.[1] National parks support $13.3

[1] *See* http://www.census.gov/compendia/statab/2010/tables/10s1215.pdf, Ex. 1.

billion of local private-sector economic activity and 267,000 private-sector jobs.[2] They also attract businesses and individuals to the local area, resulting in economic growth in areas near parks that is an average of 1 percent per year greater than statewide rates over the past three decades.[3] National parks also generate more than four dollars in value to the public for every tax dollar invested.[4] Of the number of annual park visitors in 2008, approximately 516,804 people journeyed to Theodore Roosevelt National Park spending nearly half a million dollars. The same year 845,734 people visited Badlands National Park; 573,433 visited Wind Cave National Park; 221,585 visited Voyageurs National Park and 14,038 visited Isle Royale National Park.[5]

Excessive emissions from North Dakota not only obscure the region's scenic vistas Congress sought to protect, but also contribute to a host of public health problems as well as adverse impacts to wildlife and vegetation. For example, NO_x and VOCs are precursors to ground level ozone, or smog. Ground level ozone is associated with respiratory diseases, asthma attacks, and decreased lung function.[6] SO_2 pollution contributes to respiratory problems, particularly for children and the elderly, and aggravates existing heart and lung diseases. Exposure to particulate matter, made up of sulfates and nitrates, has been associated with reduced lung function, increased susceptibility to respiratory infections, chronic bronchitis, and premature death.[7] The U.S. Environmental Protection Agency (EPA) has found that in 2015, the Regional Haze Rule also will provide substantial health benefits valued at $8.4 - $9.8 billion annually -- preventing 1,600 premature deaths, 2,200 non-fatal heart attacks, 960 hospital admissions, and over 1 million lost school and work days. The total annual cost will range from 1.4 – 1.5 billion dollars.[8] These benefits are estimated under the assumption that the Regional Haze Rule will be implemented as intended-therefore these numbers may be lower if North Dakota does not revise its plan.

The regional haze program imposes a legal obligation on the State to abate the adverse visibility effects to which its haze causing facilities contribute in order to restore visibility levels to their natural conditions as mandated by the Clean Air Act. To prevent and remedy visibility impairment to the implicated Class I areas, North Dakota can and must revise and substantially improve the draft RH SIP. A strong regional haze program will not only help protect and restore treasured landscapes and the economies that rely on them but also benefit public health. With this in mind, we offer the comments below for consideration by the NDDH and strongly encourage the Department to strengthen its regional haze plan.

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[2] Hardner and Gullison, "The U.S. National Park System, An Economic Asset at Risk" (November 2006) [prepared for the National Parks Conservation Association]. Ex. 2.

[3] Id.

[4] Id.

[5] *See* http://www.nature.nps.gov/stats/index.cfm.

[6] 70 Fed. Reg. 25162, 25169 (May 12, 2005).

[7] U.S. EPA. Air Quality Criteria for Particulate Matter (Final Report, April 1996). U.S. Environmental Protection Agency, Washington, D.C., EPA 600/P-95/001.

[8] EPA, Fact Sheet, *Final Regional Haze Regulations for Protection of Visibility in National Parks and Wilderness Areas* (June 2, 1999) at http://www.epa.gov/visibility/fs_2005_6_15.html, Ex. 3.

In addition, we note that the public comment for North Dakota's SIP was open for 30 days. It is common in other jurisdictions to provide for 45 or 60 day comment period. Given the lengthy history and technical complexity of this SIP, such an abbreviated window is not conducive to a full and fair evaluation by the public. We understand that the EPA has requested states to submit SIPs by January 15, 2010. Understandably, North Dakota would like to abide by this suggested timeline, however, the short turnaround—five business days from the end of the public comment period to the EPA deadline—does not provide NDDH an adequate amount of time to genuinely consider public comments and make needed changes to the SIP. Accordingly, we request NDDH coordinate with EPA to submit the North Dakota SIP in a timely manner without compromising full consideration of public comments.

I. The Clean Air Act and Federal Regulation Require NDDH to Abate Visibility Impairment

In 1977, the Clean Air Act declared "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution[]" where visibility has been determined to be an important value. 42 U.S.C. § 7491(a)(1) &(2). "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities[.]" 42 U.S.C. §7491(g)(3). Congress adopted the visibility protection program to protect the "intrinsic beauty and historical and archeological treasures" of specific public lands.[9] To protect these treasures, the regional haze program establishes a regulatory floor and requires states to design and implement programs at least as stringent as the national floor to curb haze causing emissions located within their jurisdictions. States are required to submit State Implementation Plans or SIPs if they host federally protected areas or the emissions of a facility located within a State "may be reasonably be anticipated to cause or contribute to any impairment of visibility" for a protected area located beyond their borders. 42 U.S.C. §7491 (b)(2).

The SIP must contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal..." including BART requirements for all eligible sources and a long-term strategy for making reasonable progress towards meeting the national goal. 42 U.S.C. §7491(b)(2)(A) &(B).

BART is defined as an emission limitation

> . . .**based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility**. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in

[9] *See* H.R. REP. NO. 95-294, at 203–04 (1977).

visibility which may reasonably be anticipated to result from the use of such technology.

40 C.F.R. §51.301, emphasis added. BART limits are required for major stationary sources that were in existence on August 7, 1977 and began operating after August 7, 1962 and emit air pollutants that may reasonable be anticipated to cause or contribute to any impairment of visibility is a Class I area. 42 U.S.C. § 7491(b)(2)(A). The term "major stationary source" is defined as sources that have the potential to emit 250 tons or more of any pollutant and fall within one of 26 categories of industrial sources defined by the Act. 42 U.S.C. § 7491(g)(7). A BART-eligible source is one that meets the above criteria and is responsible for an impact on visibility in a Class I area of 0.5 deciview or more. 40 C.F.R. Part 51, Appendix Y. BART must be installed and operated no later than five years after the SIP approval. 40 C.F.R.§51.302(c)(4)(iv).

The SIP must also provide a long-term strategy for achieving reasonable progress toward meeting natural visibility conditions at mandatory Class I areas by 2064. 40 C.F.R. §51.308(d)(1)(i)(B). If a state's reasonable progress goals do not anticipate restoring visibility to natural conditions by 2064 the state must demonstrate why the goal of attaining natural conditions by the established date is unreasonable. 40 C.F.R. §51.308(d)(1)(ii). The SIP must provide for improved visibility on the most impaired days and ensure no degradation in visibility for the least impaired days. 40 C.F.R. §51.308(d)(1)(i)(B). The long-term strategy is typically a 10-15 year plan containing enforceable measures designed to meet regional progress goals. In developing its plan, the State must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based. 40 C.F.R. §51.308(d)(3)(iii).

In developing its long-term strategy, the State must consider all anthropogenic sources of visibility impairment and evaluate different emission reduction strategies beyond those prescribed by the BART provisions. 40 C.F.R §51.308(d). The state should consider "major and minor stationary sources, mobile sources and area sources." Id. At a minimum, the state must consider the following elements:

(A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
(B) Measures to mitigate the impacts of construction activities;
(C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
(D) Source retirement and replacement schedules;
(E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
(F) Enforceability of emission limitations and control measures; and
(G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.

40 C.F.R. 51.208(d)(3)(v)(A)-(G).

North Dakota's regional haze plan falls far short of meeting reasonable progress goals. In fact, North Dakotas's draft regional haze plan will only bring the state to, at most, 38% of its 2018 regional progress target at Theodore Roosevelt National Park and even less than that at Lostwood Wilderness Area. Table 8.11 of the draft North Dakota State Implementation Plan (SIP) for Regional Haze. The State appears to be claiming that the national visibility goal of returning to natural visibility conditions by 2064 is unattainable, because the the majority of regional haze pollution comes from sources in Canada and outside the state. Draft North Dakota SIP for Regional Haze at 44-45. While it may be true that some of the pollution responsible for haze in the State's Class I areas is due to sources outside of North Dakota's control, that does not relieve the State from requiring industrial sources within North Dakota to be subject to BART emission limits reflective of the best degree of continuous emission reduction achievable, nor does it relieve the State from adopting other measures to improve visibility in North Dakota and other downwind states' Class I areas.

Furthermore, to ensure that reasonable progress goals are met, North Dakota should actively encourage other states and Canada to reduce emissions impairing visibility in its state and region. State-to-state consultations are part of the regional haze process, and North Dakota is well within its rights to formally request reductions from other states where appropriate. The U.S. EPA, in comments on the FLM version of the draft SIP, suggests that a three-prong approach is appropriate: "NDDH needs to be addressing sources within its control in North Dakota, requesting reductions from contributing states, and asking EPA to address the Canadian emissions."[10] To the extent that North Dakota has not undertaken each of these actions, it should do so. While there are multiple opportunities for North Dakota to pursue to ensure reasonable progress goals are attained, the State may not use emissions from outside sources as a scapegoat to avoid in-state action.

Our review of North Dakota's proposed BART emission limits and controls shows that the State has clearly not required emissions controls and limits that reflect BART for the BART-eligible sources. This is discussed in detail below. Further, the State has not required any source emission reductions or source retirements other than its proposed BART requirements to meet reasonable progress requirements. Regardless of the impacts that other sources outside of North Dakota have on regional haze in North Dakota's Class I area, North Dakota has a responsibility under the federal regional haze requirements to reduce haze causing emissions from its own sources of air emissions to do its part to meet the reasonable progress goals. Under the Long Term Strategy regulations, North Dakota is required to demonstrate that "it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goals for the area" even when other states contribute to visibility impairment in the State's Class I areas. 40 C.F.R. §51.308(d)(3)(ii). Thus, the State cannot shirk its responsibility to address its sources of regional haze pollution by putting the blame on sources outside the state.

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[10] U.S. EPA Region 8 Comments on August 21, 2009 Draft Regional Haze SIP (FLM Consultation Version), Enclosure 1, p. 5.

Further, the State has a responsibility to reduce emissions from North Dakota sources that are reasonably anticipated to impact visibility in other states' Class I areas. Minnesota is one such state, and Minnesota submitted a letter to the North Dakota Department of Health (NDDH) indicating the need for North Dakota electrical generating units to meet an average SO_2 limit of 0.25 lb/MMBtu as well as the need for NO_x emission reductions from North Dakota sources. September 19, 2007 letter from the Minnesota Pollution Control Agency (MPCA) to NDDH and other states (Appendix J.2.1. of the draft North Dakota Regional Haze SIP). NDDH did not agree with these requests and stated that "[a]dditional reductions from Minnesota sources may provide much greater reduction of visibility impacts." August 22, 2008 letter from NDDH to MPCA at 2 (Appendix J.2.2. of the draft North Dakota Regional Haze SIP.)

North Dakota could achieve additional reductions in visibility impairing pollutants from its own sources, but this draft regional haze SIP and BART limits do not require such reductions. As we will show below, North Dakota could achieve much greater emission reductions in haze causing pollution with available control technologies and/or by imposing more stringent emission limits reflective of the best level of continuous emission reduction in its BART determinations.

II. NDDH's Draft BART Determinations are Flawed

A. The SO_2 BART Limits Fail to Reflect the Degree of SO_2 Emission Reduction Achievable with the Best System of Continuous Emission Reductions.

NDDH simply has proposed the EPA's presumptive BART limits as BART at most of the BART-eligible coal-fired electric utility steam generating units (EGUs) that NDDH determined were subject to BART. Specifically, NDDH proposed SO_2 BART limits for Leland Olds Units 1 and 2, Milton R Young Unit 2, and Coal Creek Units 1 and 2 of 0.15 lb/MMBtu or 95% control. While NDDH purported to do a case-by-case evaluation of BART for each EGU, it appears that the case-by-case analyses were simply written to support the imposition of EPA's presumptive BART limits rather than to truly reflect the best level of continuous SO_2 emission reduction at each EGU.

EPA's BART Guidelines include "presumptive BART" emission limits for EGUs which were based on EPA's broad review of the control technologies and emission limits that could be met cost effectively at a wide range of coal-fired power plants. *See* Sections IV.E.4 and 5 of the BART Guidelines in 40 C.F.R. Part 51, Appendix Y. However, it must be stated that EPA's presumptive BART limits do not negate the need for the State to determine BART for each BART-eligible source on a case-by-case basis through a five factor analysis. The regulations and the Clean Air Act require the determination of BART to be source-specific. *See* 40 C.F.R. § 51.308(e)(1)(ii)(A); § 169A(g) of the Clean Air Act.

The five steps of determining BART are:

STEP 1 -- Identify All [fn 12] Available Retrofit Control Technologies,

> STEP 2-- Eliminate Technically Infeasible Options,
> STEP 3-- Evaluate Control Effectiveness of Remaining Control Technologies,
> STEP 4-- Evaluate Impacts and Document the Results, and
> STEP 5 – Evaluate Visibility Impacts.
>
> Fn 12: In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology – the list is complete if it includes the maximum level of control each technology is capable of achieving.

Section IV.D. of BART Guidelines at 40 C.F.R. Part 51, Appendix Y.

Clearly, EPA's BART Guidelines require an evaluation of the top level of pollution reduction achievable with each control system evaluated in a BART analysis. EPA's BART Guidelines provide that, if a control system can be operated at a wide range of control efficiencies, "the most stringent emissions control level that the technology is capable of achieving" must be evaluated. Section IV.D.3. of the BART Guidelines at 40 C.F.R. Part 51, Appendix Y. The BART Guidelines further require that "[y]ou should consider recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) when identifying an emissions performance level or levels to evaluate." *Id.*

The BART Guidelines also provide:

> In assessing the capability of the control alternative, latitude exists to consider special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, you should explain the basis for choosing the alternate level (or range) of control in the BART analysis. Without a showing of differences between the source and other sources that have achieved more stringent emissions limits, you should conclude that the level being achieved by those other sources is representative of the achievable level for the source being analyzed.

Id.

Further, while one can consider varying levels of pollution control in evaluation of a particular control device, one "must consider the most stringent level as one of the control options." *Id.*

NDDH did not follow these guidelines or otherwise meet the intent of the BART requirements because it did not evaluate the most stringent option available for reducing SO_2 from the State's EGUs as is discussed further below.

1. NDDH Cannot Take Into Account Projected Worst Case Sulfur Content of Coal in Setting BART Limits

For all of the coal-fired EGU SO_2 BART determinations, NDDH relied on worst case projections of sulfur content of the coal to be burned in justifying the SO_2 emission limits as BART. For example, for Leland Olds, which currently has an uncontrolled SO_2 rate exiting the boilers of 1.82 to 1.83 lb/MMBtu (2000-2004 average)[11], NDDH assumed an uncontrolled SO_2 emission rate of 3.02 lb/MMBtu[12]. There is no justification for assuming such a high uncontrolled SO_2 emission rate. Similarly, Coal Creek Units 1 and 2 burned coal with a sulfur content of 0.61% during 2003-2004[13], and yet NDDH relied on a worst case coal sulfur content of 1.1%, close to double the 2003-2004 average coal sulfur content, in proposing a BART SO_2 limit.[14]

Milton R. Young Unit 1, which currently has no scrubber, had an uncontrolled SO_2 emission rate exiting the boiler of 1.83 lb/MMBtu (2000-2004 average)[15]. Yet, for Milton R. Young Unit 2, which presumably burned the same coal as Milton R. Young Unit 1, NDDH assumed an uncontrolled SO_2 emission rate of 3.48 lb/MMBtu in proposing BART limits for SO_2.[16] Although NDDH's BART Determination for Unit 1 did not include an uncontrolled SO_2 emission rate, it also appears that NDDH assumed a higher-than-actual SO_2 rate for Unit 1. NDDH assumed 95% SO_2 removal would result in an emission reduction of 20,443 tpy.[17] Yet, the 2000-2004 average SO_2 emissions from Unit 1 were only 20,148 tpy.[18] If actual average emissions were reduced by the projected amount, Unit 1 would be emitting negative amounts of SO_2, which is an impossibility.

This shows that, not only did NDDH improperly rely on the worst case sulfur content coal in proposing BART limits, NDDH also inflated the baseline actual emissions for some EGUs to reflect higher sulfur content coal, and then calculated SO_2 emission reductions based on assumed levels of SO_2 removal from baseline emissions that never actually occurred. Thus, NDDH greatly overstated the emission reductions that would occur from implementation of SO_2 BART controls. Presumably, this was also carried over into NDDH's modeling conducted for the BART analyses as well.

In evaluating SO_2 BART for Stanton Unit 1, NDDH's approach was slightly different but had the same result of artificially inflating the proposed limit. Two scenarios

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[11] See NDDH's BART Determination for Leland Olds at 2-3.

[12] *Id.* at 5.

[13] See NDDH's BART Determination for Coal Creek at 9.

[14] Id.

[15] See NDDH's BART Determination for Milton R. Young at 3.

[16] *Id.* at 24.

[17] *Id.* at 7.

[18] *Id.* at 3.

were evaluated for Stanton Unit 1, burning lignite and burning Powder River Basin, or PRB, coal. While developing a limit for burning lignite, NDDH did not rely on worst case coal. Instead, it used the average of the annual SO_2 emission rate from 2001-2004, applied its assumed SO_2 control factor for each control evaluated, [19] and then, for the proposed limit, increased the calculated controlled emission rate by 33% to arrive at a 30-day average emission limit.[20] While developing an SO_2 emission limit for burning PRB coal, however, NDDH did arbitrarily rely on higher sulfur Powder River Basin coal than currently burned at Stanton Unit 1, *and* NDDH also applied a 33% increase.[21]

The purpose of BART is to reduce emissions from current levels to improve visibility, and that purpose will be ignored if BART limits are determined based on worst case sulfur content coals of the future. As we have seen with Milton R. Young Unit 1, the nonsensical nature of this approach is highlighted when it leads to projected emission reductions that are greater than actual emissions. Because NDDH is proposing BART limits based on 30-day averages, the averaging time can allow the EGU owners to take into account variability in sulfur content of coal and still comply with the limit. Further, retrofitted and upgraded wet scrubbers can achieve much higher levels of SO_2 control than the 95% control assumed by NDDH, as is discussed further below. Thus, if an EGU owner anticipates burning a higher sulfur coal in the future, it can have its scrubber designed to achieve higher levels of SO_2 removal to meet a SO_2 BART emission limit that is set based on the coal currently burned at the EGU. There are also other options that the EGUs could use to address unusually high levels of sulfur in the coal, such as blending with a lower sulfur coal, rejecting high sulfur coal altogether, or coal drying, as has been demonstrated at the Coal Creek facility.[22] Thus, there is no justification to base SO_2 BART limits on the ultimate worst case sulfur content coal to be burned at these units.

2. The Proposed SO_2 BART Limits Fail to Reflect the Degree of SO_2 Reduction Achievable with the Best SO_2 Controls

All but one[23] of NDDH's SO_2 BART determinations requires the use of new or upgraded wet scrubbers, a technology capable of reducing SO_2 emissions by 99% or more. Despite this achievable control efficiency, NDDH simply proposed EPA's presumptive BART limits for SO_2: either 95% control or an emission limit of 0.15 lb/MMBtu. While wet scrubbers can routinely achieve the highest levels of SO_2 control, NDDH's proposed BART emission limits fail to reflect this.

[19] See NDDH's BART Determination for Stanton Unit #1 at 4.

[20] *Id.* at 8. Note that NDDH did not adequately justify applying a 33% increase to the controlled SO2 emission rate based on annual average uncontrolled SO2 emission rates, as we will discuss further below.

[21] *Id.* at 17, 22.

[22] To the extent that it may be capable of additional reductions of NOx and SO2 above and beyond the proposed technologies, coal drying should have been evaluated as part of the BART determinations as well. http://www.greatriverenergy.com/makingelectricity/dryfining_factsheet.pdf, Ex. 4.

[23] As discussed below, a wet scrubber was not required for Stanton Unit 1.

Wet scrubbers can achieve 99% removal efficiency. A prime example is the Chiyoda CT-121 FGD. Vendor information for this technology indicates that this scrubber has achieved 98-99% SO_2 removal even with low sulfur coal.[24] For example, the Chiyoda's bubbling jet reactor has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level of control while treating gases with inlet SO_2 concentrations of 1.78 lb/MMBtu.[25] Based on actual SO_2 emissions data, the North Dakota BART-eligible EGUs have inlet SO_2 concentrations of this level or higher. This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[26] It also has been demonstrated in the U.S. at the University of Illinois's Abbott power plant, Georgia Power's Plant Yates[27], Dayton Power & Light's Killen Unit 2,[28] and Plant Bowen Unit 3.[29] It has also been licensed for installation on several additional units in the US, including the other three units at Plant Bowen in Georgia, the other units at Dayton Power & Light's Killen plant, Dayton Power & Light's Stuart plant, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[30] Black & Veatch and Southern Company are both U.S. licensees. Further, this technology also has shown to be very effective in removing fine particulates, oxidized and elemental mercury, and acid gases, and the technology uses less energy compared to traditional wet scrubbers.

Further, Mitsubishi, another vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including for coal-fired boilers.[31, 32, 33]

Finally, a Lake Michigan Air Directors Consortium ("LADCO") and the Midwest Regional Planning Organization ("MRPO") presentation indicated that advanced FGD

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[24] *See* Black & Veatch vendor brochure on CT-121, Ex 5.

[25] Yasuhiko Shimogama, Hirokazu Yasuda, Naohiro Kaji, Fumiaki Tanaka, and David K. Harris, Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant, Paper No. 27, presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, Ex. 6.

[26] CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html, Ex. 7.

[27] Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

[28] See Black & Veatch, First Black&Veatch/Chiyoda Wet Flue Gas Desulfurization System in North America Successfully Goes Operational, Ex. 8.

[29] Blankinship, Steve, Go Take a Bath, Power Engineering, October 2008, available at http://pepei.pennnet.com/display_article/342997/6/ARTCL/none/none/1/Go-Take-a-Bath/, Ex. 9.

[30] Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005, Ex. 10; Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005, Ex. 11.

[31] Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4, Ex. 12.

[32] Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD, Ex. 13.

[33] Mitsubishi High SO2 Removal Experience, Ex. 14.

technologies could achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removed. Ex. 15. These costs are well within the range that EPA normally considers to be cost effective in best available control technology (BACT) analyses.[34] Further, these costs are also well within the range of what other states have found to be cost effective for SO_2 BART determinations.[35]

3. The Proposed SO_2 BART Limits Should Be Expressed Multiple Ways

Many of the proposed limits are listed either as lb/mmbtu OR as percent removal efficiency. To ensure continuous compliance with "the degree of reduction achievable through the application of the best system of continuous emission reduction" over the range of possible coal sulfur content, all the SO_2 BART limits should be expressed both ways. Without a minimum required removal efficiency, the achievable SO_2 removal efficiency will not be required at lower coal sulfur content.

Further, a maximum cap on emissions should be required. EPA guidance suggests that emission limits be expressed both as a maximum allowable emission rate per unit time (e.g., lb/hr, tons/year) to reflect application of emissions controls at maximum capacity *and* as an instantaneous emission limit (e.g., lb/mmbtu). NSR Manual, pp. B.56, H.5, I.2, I.4. This is good practice for compliance purposes, and also serves as an actual time-based limit for modeling purposes.

4. NDDH's Proposed SO_2 Emission Limits Fail to Reflect BART

Thus far, three general flaws have been noted in the NDDH SO_2 BART determinations: use of worst case coal sulfur content; failure to reflect the actual removal efficiency of wet scrubbers; and failure to express limits in multiple ways. These errors and others noted below on a case-specific basis combine to allow for significantly higher SO_2 emission rates from the EGUs evaluated for BART. Table 1 below highlights this impact.

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[34] $10,000/ton in 2001, equivalent to over $13,000/ton today. *See* expert report of Matt Haber - EPA, *Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois*, prepared for the United States in connection with United States v. Illinois Power Company and Dynegy Midwest Generation, Inc., Civil Action 99-883-MJR, in the U.S. District Court for the Southern District of Illinois, April 2002, p. 17, Ex. 16; Memorandum of John S. Seitz to Air Division Directors, BACT and LAER for emissions of nitrogen oxides and volatile organic compounds at Tier 2/Gasoline Sulfur Refinery Projects (Jan. 19, 2001), at 3, Ex. 17.

[35] See National Park Service Spreadsheet "EGUs with Proposed BART SO2 Controls" dated November 13, 2009, Ex. 18.

Table 1: Proposed and Appropriate BART Limits for EGUs Evaluated By NDDH

Facility	Proposed BART	Appropriate BART
Leland Olds Units 1 and 2	95% removal OR 0.15 lb/MMBtu	95 – 99% removal AND 0.03 – 0.091 lb/MMBtu
Milton R. Young Unit 1	95% removal	95 – 99% removal AND 0.035 – 0.094 lb/MMBtu
Milton R. Young Unit 2	95% removal OR 0.15 lb/MMBtu	95 – 99% removal AND 0.035 – 0.094 lb/MMBtu
Coal Creek Units 1 and 2	95% removal OR 0.15 lb/MMBtu	95 – 99% removal AND 0.03 – 0.087 lb/MMBtu
Stanton Unit 1	90% removal OR 0.24 lb/MMBtu	95 – 99% removal AND 0.02 – 0.085 lb/MMBtu

a. Leland Olds

For Leland Olds, NDDH proposed SO_2 BART limits for each unit of either 95% removal of the inlet SO_2 concentration to the scrubber or 0.15 lb/MMBtu on a 30-day average basis based on use of wet scrubbers. The proposed emission limitation of 0.15 lb/MMBtu only reflects 91.8% SO_2 removal at each unit based on the annual average of uncontrolled SO_2 emissions at each unit. Such an SO_2 removal efficiency falls far short of what is achievable with a wet scrubber at the Leland Olds units. A removal efficiency of 95% control reflects the minimum level of SO_2 removal that is achievable with a wet scrubber. Thus, at the minimum, the BART emission limit should be based on 95% removal from the annual average of the uncontrolled SO_2 emissions at each unit - or a limit of 0.091 lb/MMBtu. Because the proposed 95% removal is an alternate and not concurrent limit, the fact that NDDH has also proposed an alternative limit of 95% SO_2 removal will not ensure 95% removal is required until the uncontrolled SO_2 emissions increase significantly, to about 2.8 lb/MMBtu. Thus, it is imperative that the lb/MMBtu limit reflect no less than 95% control off of current coal in order for the BART limit to reflect at least the minimum level of SO_2 control efficiency of a wet scrubber.

Indeed, based on the discussion above regarding the SO_2 removal capabilities of a wet scrubber, a more appropriate BART limit would reflect 98-99% SO_2 removal. Even assuming the worst case uncontrolled SO_2 emissions identified by NDDH of 3.20 lb/MMBtu, 98% removal would reflect an emission limit of 0.064 lb/MMBtu. This SO_2 emission limit based on worst case coal and an achievable level of SO_2 removal would reflect 96.5% SO_2 removal from current coal – a control efficiency that is clearly achievable with a wet scrubber. Ninety-nine percent removal off of worst case coal at Leland Olds would equate to a SO_2 emission limit of 0.03 lb/MMBtu. With current coal, this would reflect 98.4% removal. This emission level and SO_2 removal efficiency has been shown to be achievable and has been achieved in practice.

The attached National Park Service spreadsheet of best available control technology (BACT) determinations for coal-fired power plants shows that BACT limits as high as the 0.15 lb/MMBtu SO_2 BART limits proposed for the Leland Olds units are unheard of. Ex. 19. The proposed permit for the Plant Washington facility requires as part of the facility's BACT limits a 97.5% SO_2 removal efficiency requirement that would apply on a 30-day rolling average regardless of the type of coal burned.[36] This facility may burn Powder River Basin coal or Central Appalachian coal or a combination of the two. The Desert Rock facility, which will burn low sulfur western coal, is subject to an SO_2 BACT limit of 0.060 lb/MMBtu on a 24-hour basis (Ex. 21), and the proposed Toquop (Ex. 22) and Ely Energy Center [37](Ex. 23) permits, both of which would burn Powder River Basin coal, also included BACT limits of 0.06 lb/MMBtu for SO_2. As Ex. 25 shows, there are numerous coal-fired units that are achieving SO_2 emission rates much lower than the 0.15 lb/MMBtu SO_2 BART limit proposed for the Leland Olds Units. The lowest SO_2 emission rates being achieved are at the Pleasant Prairie units which are emitting SO_2 at 0.021 to 0.027 lb/MMBtu with wet scrubbers.

Thus, for all of the reasons discussed above as supported by the attached documentation, BART emission limits of no higher than 0.091 lb/MMBtu and as low as 0.03 lb/MMBtu should have been evaluated as BART for the Leland Olds Units. Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. There is no justification for increasing the emission rate determined from annual average coal characteristics to arrive at a higher 30-day average emission limit as NDDH has proposed. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or use of lower sulfur content coal. In addition to imposing a numerical emission limit, NDDH should also set a minimum control efficiency requirement not as an alternative limit but as a second BART limit, to ensure the achievable SO_2 removal efficiency is required regardless of the type of coal burned.

Thus, the proposed 0.15 lb/MMBtu SO_2 BART limits fall far short of reflecting the best system of continuous emission reduction at the Leland Olds units. In fact, a much more appropriate SO_2 BART limit would be in the range of 0.03 to 0.091 lb/MMBtu, 30-day average, along with an SO_2 removal efficiency requirement of no less than 95% control.

b. Milton R. Young

For Milton R. Young Unit 1, NDDH has proposed use of a wet scrubber and an SO_2 BART limit of a 95% removal efficiency from the inlet SO_2 concentration to the scrubber, to be achieved on a rolling 30-day average basis. For the reasons previously discussed and the documentation attached, 95% control does not reflect best system of continuous emission reduction of SO_2 emissions from Milton R. Young Unit 1. Instead, an SO_2 removal efficiency of 98 to 99% should be achievable with a wet scrubber and the coal to be burned at Milton R. Young Unit 1.

Along with an SO_2 removal requirement, NDDH should also impose an emissions limit. Otherwise, it is difficult for NDDH to project emissions from Milton R. Young Unit 1 for use in air modeling analyses such as PSD increment analyses or for the visibility modeling done for this regional haze SIP and subsequent SIP submissions. Based on the same reasoning provided

[36] Proposed Plant Washington PSD Permit (Ex. 20) at Condition 2.14.

[37] NV Energy no longer plans to build the Ely Energy Center, and officially withdrew its application to the state Public Utilities Commission in June 2009. See http://www.lvrj.com/news/breaking_news/48923992.html, Ex. 24.

above, the numerical SO_2 BART limit should be based on no less than 95% removal from the current uncontrolled emission rate of 1.88 lb/MMBtu - 0.094 lb/MMBtu. However, as discussed above, higher SO_2 removal efficiencies are achievable. Even using NDDH's worst case uncontrolled SO_2 emission rate for Milton R. Young Unit 1 of 3.48 lb/MMBtu, 98% SO_2 removal would reflect an emissions limit of 0.070 lb/MMBtu. Ninety-nine percent removal would result in an emissions limit of 0.035 lb/MMBtu. As shown in the attachments to this letter, such emission rates have been required as BACT and/or have been met in practice.

Thus, the proposed 95% SO_2 removal efficiency requirement for Milton R. Young Unit 1 falls far short of reflecting the best system of continuous emission reduction at the unit. A much more appropriate SO_2 BART limit would be in the range of 0.035 to 0.094 lb/MMBtu, 30-day average, along with a 95% or higher SO_2 removal efficiency requirement.

Milton R. Young Unit 2 is already equipped with a wet scrubber which, according to NDDH, achieves approximately 65% SO_2 control. NDDH has proposed requiring upgrades to the scrubber to achieve 95% control or meet an SO_2 emission limit of 0.15 lb/MMBtu, 30-day average, as BART for Milton R. Young Unit 2. NDDH found the costs to upgrade the scrubber to 95% control to be quite reasonable. Given the low costs for upgrading the scrubber to achieve 95% removal, it should also be cost effective to require the scrubber to be upgraded to achieve the level of SO_2 control that is achievable with a wet scrubber – up to 98-99% SO_2 removal.

Along with an SO_2 removal requirement, NDDH should also impose an emissions limit as BART for Unit 2. Because the same coal is burned and the same control efficiencies can be expected, the same analysis applies to Unit 2 as that described for Unit 1 above.
Thus, the 95% removal efficiency requirement that would apply to Unit 2 does not satisfy BART. An SO_2 emission limit in the range of 0.035 – 0.094 lb/MMBtu along with a high SO_2 removal efficiency requirement should instead be required as BART for Unit 2.

Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. There is no justification for increasing the emission rate determined from annual average coal characteristics to arrive at a higher 30-day average emission limit as NDDH has proposed. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or use of lower sulfur content coal.

c. Coal Creek

For Coal Creek Units 1 and 2, NDDH proposed SO_2 BART limits for each unit of either 95% removal of the inlet SO_2 concentration to the scrubber or 0.15 lb/MMBtu on a 30-day average basis based on use of wet scrubbers. Assuming each unit achieved 68% SO_2 removal efficiencies as claimed by NDDH, then the uncontrolled SO_2 emissions at the inlet to the scrubber averaged over 2000-2005 ranged from 1.59 to 1.71 lb/MMBtu. The 0.15 lb/MMBtu emission limit only reflects 90.6% to 91.4% SO_2 removal based on the annual average of uncontrolled SO_2 emissions at each unit. Such SO_2 removal efficiencies fall far short of what is achievable with a wet scrubber at the Coal Creek units. A removal efficiency of 95% control reflects the minimum level of SO_2 removal that is achievable with a wet scrubber. Thus, at the minimum, the BART emission limit should be based on 95% removal from the annual average of the uncontrolled SO_2 emissions at each unit - or a limit of 0.080 to 0.087 lb/MMBtu. Because the proposed 95% removal is an alternate and not concurrent limit, the fact that NDDH has also proposed an alternative limit of 95% SO_2 removal will not ensure 95% removal is required until the uncontrolled SO_2 emissions increase significantly, to about 2.8 lb/MMBtu. Thus, it is imperative that the lb/MMBtu limit reflect no less 95% control off of current coal.

Indeed, based on the discussion above regarding the SO_2 removal capabilities of a wet scrubber, a more appropriate BART limit would reflect 98-99% SO_2 removal. Even assuming the worst case uncontrolled SO_2 emissions identified by NDDH of 2.92 lb/MMBtu[38], 98% removal would reflect an emission limit of 0.058 lb/MMBtu. And this SO_2 emission limit based on worst case coal and an achievable level of SO_2 removal would reflect at most 96.6% SO_2 removal from current coal – a control efficiency that is clearly achievable with a wet scrubber. Ninety-nine percent removal off of worst case coal at Coal Creek would equate to a SO_2 emission limit of 0.03 lb/MMBtu. With current coal, this would reflect 98.2% removal. These emission rates and control efficiencies are achievable as evidenced by the previously referenced and attached documentation.

Thus, for all of the reasons discussed above as supported by the attached exhibits, SO_2 emission limits of no higher than 0.087 lb/MMBtu and as low as 0.03 lb/MMBtu should have been evaluated as BART for the Coal Creek Units. Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. There is no justification for increasing the emission rate determined from annual average coal characteristics to arrive at a higher 30-day average emission limit as NDDH has proposed. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or use of lower sulfur content coal. In addition to imposing a numerical emission limit, NDDH should also impose a minimum control efficiency requirement not as an alternative limit but as a second BART limit, to ensure the achievable SO_2 removal efficiency is required regardless of the type of coal burned. Therefore, a SO_2 control efficiency requirement should also be imposed as BART, no less than 95% control.

d. Stanton Unit 1

For Stanton Unit 1, NDDH proposed as BART for SO_2 the use of a spray dryer with a fabric filter and an SO_2 emission limit of 0.24 lb/MMBtu or an SO_2 removal efficiency of 90%, both on a 30-day rolling average basis. This emission limit was derived assuming 90% removal from the highest calendar year average SO_2 emissions of 1.81 lb/MMBtu, increased by 33% to adjust from an annual average to a 30-day average. NDDH has provided absolutely no justification for this 33% increase. Given that the limit is based on the worst year of uncontrolled SO_2 emissions, that the assumed control efficiency of the spray dryer is much lower than what can actually be achieved in practice with a spray dryer, and that Stanton Unit 1 also

[38] This was calculated from the table of future case emissions rates and the expected control efficiencies of the various options evaluated, Coal Creek BART Determination at 10.

burns Powder River Basin (PRB) coal which has much lower uncontrolled SO_2 emissions, there is no valid justification for NDDH to increase the derived emission rate reflective of 90% control by 33%.

Spray dryers can achieve greater than 90% SO_2 removal. There have been several proposed low sulfur PRB coal-fired power plants that have proposed to use dry scrubbers to meet PSD requirements and that are subject to much lower SO_2 BACT limits than 0.23 lb/MMBtu. Those facilities include the Newmont Nevada TS power plant, the proposed White Pine power plant[39], Toquop, and the Dry Fork power plant. The Newmont Nevada power plant is subject to a minimum 95% SO_2 removal efficiency requirement when burning coal with a sulfur content equal to or greater than 0.45% and is subject to a minimum 91% SO_2 removal efficiency when burning coal with sulfur content less than 0.45%.[40] This facility is currently operating in compliance with its limits. The Newmont Nevada plant is also subject to an SO_2 BACT limit of 0.065 lb/MMBtu when burning coal with less than 0.45% sulfur content. The proposed Toquop permit included an SO_2 BACT limit of 0.06 lb/MMBtu on a 24-hr average basis.[41] The Dry Fork power plant in Wyoming, which is also currently under construction, will burn Powder River Basin coal, will be equipped with a dry scrubber, and is subject to an SO_2 BACT limit of 0.07 lb/MMBtu.[42] Other examples of low SO_2 emission limits and high SO_2 removal rates being required as BACT can be found in the National Park Service's spreadsheet of BACT determinations for coal-fired electrical generating units, Ex. 19.

Regardless of whether NDDH underestimated the effectiveness of a spray dryer, a wet scrubber can remove an even greater amount of SO_2 than a spray dryer. Although NDDH did not find the costs of a wet scrubber at Stanton Unit 1 to be excessive, NDDH discounted the use of a wet scrubber because it determined the increased amount of SO_2 removed would not provide that much of a visibility improvement. The cost effectiveness of the wet scrubber at 95% removal for Stanton Unit 1 was actually quite reasonable at $1,480 per ton of SO_2 removed. Stanton BART Determination at 5. As shown in the National Park Service spreadsheet of BART determinations (Ex. 18), there are several instances where wet scrubbers were required to meet SO_2 BART requirements with similar or even higher costs on a \$/ton of SO_2 removed basis, specifically Clay Boswell Unit 3 (\$1,640/ton) and Naughton Units 1 (\$1,707/ton) and 2 (\$1,700/ton). There are also several instances of dry scrubbers being required as BART for SO_2 with even higher cost effectiveness values than \$1,480 per ton, including Boardman (\$3,053/ton), Martin Drake Units #6 (\$2,765/ton) and #7 (\$2,276/ton), Dave Johnston Units #3 (\$1,848/ton) and #4 (\$4,743/ton), and Silver Bay (\$7,309/ton), among others. Thus, the cost of a wet scrubber at Stanton Unit 1 is cost effective and is well within the range of the costs required at other similar EGUs to meet BART for SO_2. Given that North Dakota is far from meeting reasonable progress goals in remedying existing visibility impairment, NDDH must require as BART the most effective SO_2 control – especially when it is as cost effective as a wet scrubber would be at Stanton Unit 1.

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[39] In March 2009, LS Power "indefinitely postpone[d]" plans to build the White Pine power plant. http://www.lasvegassun.com/news/2009/mar/05/second-coal-fired-plant-canceled-nevada/, Ex. 26.

[40] *See* Section V.A.2.a.8. of Newmont Nevada Permit, Ex. 27.

[41] *See* Section V.A.2..a.(8) of draft Toquop permit, Ex. 22.

[42] *See* Dry Fork PSD Permit, Ex. 28.

In addition, as discussed above and in the attached exhibits, wet scrubbers can achieve higher than NDDH's assumption of 95% removal, as high as 98-99% SO_2 removal. If a proper SO_2 removal efficiency was taken into account, the cost effectiveness of a wet scrubber at Stanton Unit 1 would be even lower and the benefit to visibility in the affected Class I areas would be even greater.

Because the cost of a wet scrubber at Stanton Unit 1 is cost effective and because a wet scrubber will reduce SO_2 emissions to a much greater extent than a dry scrubber, NDDH must require the use of a wet scrubber as BART for SO_2 at Stanton Unit 1.

Along the same lines as our previous comments, the SO_2 BART limit with a wet scrubber should be no less than 95% removal off of current coal, or an emission limit of 0.085 lb/MMBtu. As previously stated and shown by the attached exhibits, 98-99% SO_2 removal should be achievable with a wet scrubber, which would equate to emission limits of 0.034 lb/MMBtu to 0.02 lb/MMBtu. These emission rates and control efficiencies are achievable as evidenced by the previously referenced and attached documentation.

Thus, for all of the reasons discussed above, a wet scrubber should have been required as BART for Stanton Unit 1. SO_2 emission limits of no higher than 0.085 lb/MMBtu and as low as 0.02 lb/MMBtu should have been evaluated as BART for the Stanton Unit 1. Such limits should be readily met on a 30-day average basis, especially because higher SO_2 removal efficiencies than represented by this range of more appropriate BART limits could be met with a wet scrubber. Thirty day average emission limits are long term average emission limits, and peaks in emissions can be smoothed out with increased SO_2 removal efficiencies and/or with the use of lower sulfur content coal. In addition to imposing a numerical emission limit, NDDH should also set a minimum control efficiency requirement not as an alternative limit but as a second BART limit, to ensure the achievable SO_2 removal efficiency is required regardless of the type of coal burned. This is especially important for Stanton Unit 1 which may burn two different types of coal with different uncontrolled SO_2 emission rates. The minimum control efficiency requirement should be no less than 95% control for a wet scrubber.

5. There Are Other Benefits to NDDH Requiring Stringent SO_2 BART Limits that NDDH Must Take Into Account

Along with providing for improved visibility, there are also other environmental benefits to higher SO_2 removal requirements. Specifically, very low SO_2 emission rates, on the order of single digit parts per million (ppm) concentrations, will be needed for the effective removal of carbon dioxide (CO_2) from the gas stream. Many of the amine-based CO_2 control methods currently under development are very sensitive to sulfur and thus require very low SO_2 inlet concentrations, on the order of 1 to 2 ppm.[43] It will be more cost effective and operationally simpler to design and install controls in one retrofit program.

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[43] Chuck Dene, Lesley A. Baker, and Robert J. Keeth, FGD Performance Capability, Mega 2008, Ex. 29.

It is well recognized that it is not a matter of if but when Congress and/or EPA will mandate CO_2 reductions from industrial sources such as EGUs. Thus, if a more effective SO_2 control technology and more stringent control requirements will better prepare North Dakota's EGUs to be able to effectively remove CO_2 in the future, that must be taken into account in the BART analysis as another environmental benefit of a lower SO_2 emission limit. Indeed, as described above, there are wet scrubber technologies available that can remove 99+% of the SO_2.

Further, lower emissions of SO_2 that are achievable with wet scrubbers also equate to lower $PM_{2.5}$ concentrations since there will be less SO_2 in the air to contribute to sulfate formation. Studies have demonstrated that sulfate addition to sulfate-limited water bodies or wetlands can increase the transformation of mercury to its neurotoxic form, methylmercury.[44] Thus, with lower SO_2 emissions from North Dakota's EGUs, the result should be less sulfate deposition which should decrease methylization of mercury.

All of the above must be taken into account by NDDH in proposing SO_2 BART limits for the State's BART-eligible EGUs. NDDH must require the best designed and most effective SO_2 controls on its BART-eligible EGUs – i.e., wet scrubbers designed to achieve 98-99% SO_2 removal – to meet the regional haze requirements of the Clean Air Act for the State's Class I areas.

B. NO_x BART Comments

The following comments are provided with respect to the proposed NO_x BART levels in the draft RH SIP proposed by NDDH. At the outset, it must be noted that technical issues pertaining to NO_x BART for the various coal-fired electric utility units, which are the major NO_x sources affecting visibility and regional haze in Class I areas in North Dakota and neighboring states, have been under discussion, in one form or another going back to roughly 2006. As such, it is impossible to provide meaningful comments on all aspects of NO_x BART in the allowed 30-day time period for public comment. This is particularly so given that the public comment period (ending January 8, 2010) coincided with major holidays and year end vacation periods, minimizing the ability to fully flesh out important aspects of the proposed BART. As such, the focus of the comments is on the following most important issues:

(a) The erroneous determination that high dust Selective Catalytic Reduction (HDSCR) is technically infeasible at each and any of the coal-fired electric utility units under consideration;
(b) The erroneous determination that tail end or low dust SCR (TESCR or LDSCR) are rejected based on cost ineffectiveness considerations at each and any of the coal-fired utility units under consideration.

[44] *See, e.g.*, Jeremiason, Jeff D. et al., Sulfate Addition Increases Methylmercury Production in an Experimental Wetland, Environ. Sci. Technol., 2006, 40, 3800-3806 (Ex. 30); See also Krabbenhoft, David P. *et al.*, Unravelling the Complexities Mercury Methylation in the Everglades: The Use of Mesocosms to Test the Effects of "New" Mercury, Sulfate, Phosphate, and Dissolved Organic Carbon, available at http://sofia.usgs.gov/projects/merc_carbon/hgmeso_geer03abs.html, Ex. 31.

The net result of rejection of SCR of any design at the coal fired units is that otherwise large NO_x reductions from these major sources, which could have accrued, and benefitted air quality in North Dakota and neighboring states, will not occur. That this outcome is based on erroneous regulatory and technical reasoning is untenable.

It should be noted that, due to the lack of time, the following issues could not be extensively commented upon. However, they are noted in summary or brief form below. We reserve the right to provide additional comments on these and related topics at a later date:

(a) The process by which North Dakota selected the NO_x sources to be analyzed as part of the SIP.
(b) The process by which certain emission units were selected at sources and source categories which were found to significantly impact visibility, either as part of being BART-eligible sources or under the Reasonable Progress provisions of the applicable regulations.
(c) The lack of technical basis for the assumed control efficiencies in most of the NO_x control options. For example, in the case of SCR, efficiencies of 80% or 90% or 93% are variously assumed, without basis or consistency.
(d) The lack of any support whatsoever for the level of cost-effectiveness which appears to be the basis for rejection of technologies (such as TESCR and LDSCR) on cost-ineffectiveness grounds. Nothing in the EPA guidelines for BART determinations established a bright-line cap on the cost-effectiveness expressed on $/ton reduced grounds. References to EPA's presumptive limits ($1,300/ton reduced) as a cap in this regard is fatally flawed. Numerous BART determinations in other states RH SIPs have accepted NO_x controls at levels higher than this level.[45]
(e) The improper use of incremental cost-effectiveness, as a tool to reject technologies (such as TESCR and HDSCR) which are otherwise cost-effective, even under the flawed and worst-case analyses presented by the utilities (and accepted by the State). EPA has noted the error in relying on this metric in its comments. However, such direct and express criticism seems to have had no effect in ND's analysis and proposal.
(f) The lack of discussion and analysis of cost-effectiveness expressed in terms of $/dv improved. This metric, clearly relevant in this regard, will allow comparisons of cost-effectiveness for North Dakota sources with those from other sources in other states subject to RH NO_x reductions.
(g) The lack of explicit discussion of how each of the 5 statutory factors was used or weighed in the BART determinations.
(h) The lack of support for how details such as the BART limits themselves were arrived at in terms of their averaging time. In other words, why shorter averaging times (such as 7-day or 24-hour averages) were not considered – especially given that visibility impacts can occur on short durations.
(i) The exception accorded to startup and shutdown periods, even though 30-day averaging time periods are used for the recommended BART limits. This is without technical and regulatory basis.

[45] See National Park Service Spreadsheet "EGUs with Proposed BART NOx Controls" dated November 13, 2009, Ex. 32.

Finally, it should be noted that there was insufficient time to properly critique NO_x BART for the other NO_x sources (other than the utility boilers).

1. High Dust SCR (HDSCR) is Technically Feasible

As noted earlier, the applicability of SCR as NO_x control – universally agreed to by all parties as being the technology with the highest degree of NO_x reduction potential (upwards of 90%, after consideration of in-boiler NO_x controls such as low NO_x burners or over-fire air etc.) – has been the subject of technical discussion in North Dakota since at least 2006. Not only were such discussions central to the consent decree implementation at the Milton R. Young units, but they were also part of the initial BART submittals of the various affected companies.

It appears that after opposing any type of SCR (high dust, tail end or low dust) for years on technical infeasiblity grounds, the State of North Dakota finally revised its position recently that tailend and low dust SCR were technically feasible after all. While this is a positive shift, we believe that the State has not provided a technical or regulatory basis for continuing to reject the even most promising (and likely more cost-effective) option that HDSCR is also technically feasible.

Since the State's position regarding HDSCR is the same in the case of any of the BART analyses (see Appendix B.5), comments on this aspect are provided in general, without particular reference to specific units. It should be noted that the State's position is an amalgam of all of the arguments that have been pushed consistently by the affected units, their owners, their technical consultants (Burns and MacDonnell, Sargent and Lundy, and others) with regards to SCR for the last many years.

The central issue seems to be the use (or lack of use) of technical judgment on the part of the State. An important secondary issue seems to be the State's rejection of technical arguments and support from a most important source – namely the vendors of SCR catalysts themselves.

The State's technical infeasibility rejection of HDSCR boils down to a circular argument. Basically, the State has taken the following position:

(a) that each of the boilers at issue burns some form of North Dakota lignite coal (either exclusively or in combination with other fuels such as Powder River Basin (PRB) sub-bituminous coal);
(b) that North Dakota lignite is both unique and highly variable in its properties – such as heating value, ash content, sodium content, sulfur content, moisture content, etc. In fact, in the State's view, it is so unique that there are no other similar or comparable aspects to any other lignites or brown coals anywhere in the world nor any other fuels such as biomass or wood;
(c) that HDSCR has not been applied at any North Dakota lignite fired units (which are only used in North Dakota utility units) to date (with the one, flawed exception at Coyote back many years ago, which will be discussed shortly);

(d) that since HDSCR has not been applied at any North Dakota lignite fired units successfully and for many years, there is no basis to conclude that it can be used successfully.

The circular argument is obvious. NDDH basically wants proof that HDSCR will work successfully before allowing HDSCR to be implemented – yet it demands that this proof be obtained from the very universe of sources (and only those) which are the subject of its analysis. This is akin to saying that a control technology will not work at a particular facility because it has not been tried there yet.

It is not unusual for "new" technologies to be faced with such first-time applicability challenges in a particular source category. Of course, HDSCR is not "new" in any traditional sense - it has been demonstrated successfully in other, closely related source types. In fact, implementation of BART[46] relies on the fact that emissions reductions will often accrue from first-time application of "new" technologies to various source categories. Otherwise the inherent "technology-forcing" aspect of BACT and BART would not be realized.

There is no debate that HDSCR has been successfully to all boiler types in other coal-fired applications including bituminous coals, sub-bituminous coals, other lignites, brown coals, biomass, and combinations of these fuels. There is also no debate that HDSCR has been successfully applied to all of the boiler technologies at issue here – namely cyclone, tangential fired and wall fired boilers.

Thus, the only issue is whether, in light of its widespread and continued successful use in closely related sources types such as other coal-fired applications, HDSCR can be successfully "transferred" to North Dakota lignite fired units that are either cyclone or tangential fired or wall fired (which is the universe at issue at the present time)? We believe that the overwhelming evidence in the record suggests that the answer to this question is Yes.

Typically, first-time applicability is the result of careful and proper technical consideration by the regulatory agency of the following:

(a) reliance on technology-transfer from other similar sources, broadly construed;
(b) proper reliance on pilot tests, if such tests were properly designed and conducted;
(c) reliance on key technology suppliers such as vendors, who bear the risk of failure – commercially, and reputationally; and
(d) fundamental assessment of the likely risk factors that may make the technology a failure.

Of course there will be risks inherent in the first-time application of any technology (new or old) to a new source category. We do not believe that demanding zero-risk as a pre-requisite is proper. Yet, we believe that this is exactly what North Dakota seems to want in its circular argument discussed above.

[46] We note that implementation of BART can and should necessarily encompass a review of relevant BACT analysis.

We believe that North Dakota has improperly disregarded key aspects of the above considerations, in particular the rejection of explicit assurances from at least two experienced and reputable SCR catalyst vendors, as far back at 2007/2008, that HDSCR could be installed at the units at issue. Substituting its own judgment in place of such vendors was improper. Relying only on industry-funded researchers, engineering companies and consultants (who are not technology providers) is also improper.

Basically, for the last 4 years, and in spite of much evidence to the contrary, North Dakota has chosen to disregard the plain fact that HDSCR can be successfully applied to each and every unit at issue. Of course, such application will require case-by-case design and analysis. Of course, such application will inherently involve some technical risk. To the extent that such risks can be mitigated by coupon tests, or pilot tests, these should be conducted either at the units or at vendor locations. That each utility was vehemently opposed to any such tests, relying on false regulatory arguments that these somehow violate how BART is determined, underscores the outcome-determinative nature of the present proposed analysis. The fact is that BART allows for technology transfer. We know of no successful technology transfer that is not preceded by prudent engineering judgment, supported by appropriate testing. Thus, excluding the possibility of any such type of testing equates to reading-out technology transfer from the definition of BART – which directly contradicts EPA guidance and Congressional intent.

Below, we provide some comments on key technical concerns raised by the State in attempting to support its position that HDSCR is not technically feasible.

a. Variability of Fuel Composition

The State notes that North Dakota lignites (or lignite from a particular mine, such as the Center Mine, the source of the Milton R. Young units) are highly variable in heat and ash content and in the constituents that make ash, and that such variability will affect SCR design and operation. While this may be true, it is true of all coals, worldwide. We know of no coal-fired boiler designer/operator or SCR designer/operator who does not face fuel variability. However, such variability is no reason to conclude that HDSCR will be precluded from successful application. In fact, designers routinely factor in such variability such that equipment can operate over a wide range of variability. Thus, it is a matter of proper design, anticipating such variability, which is required by a case-by-case analysis. Frankly, pointing to such variability as a reason for technical infeasibility of HDSCR shows the weakness of the State's argument.

b. Results of the Coyote Pilot Testing

The State correctly states that "the only pilot testing that has ever been conducted on a unit firing North Dakota lignite was at the Coyote stations. The pilot scale SCR was plugged after 2 months and little useful data was obtained." In fact, the failure of the Coyote stations test is noted as a central point in the State's determination that HDSCR cannot be successful. Yet, in key respects, the State intentionally or otherwise misrepresents these tests and their conclusions. This is puzzling because the State correctly notes that "the pilot testing....in hind-sight, was ill-designed for a unit combusting North Dakota lignite..." In fact, it is undisputed that this test was poorly designed and executed for the following reasons:

(a) The catalyst used at the Coyote station test was previously used at the Baldwin station. While it was supposedly cleaned between tests, the nature of such cleaning and its effectiveness are unknown. It is more than likely that the catalyst was impaired before tests even began at Coyote station. At any rate, it is undisputed that it was not new or fresh catalyst;
(b) The catalyst design was improper with regard to pitch, measure of cell spacing that influences gas flow and ash deposit. That resulted in rapid plugging in a short amount of time. As a result, no deactivation data were obtained. There is no support whatsoever that this type of catalyst or the same pitch would be proper or be used in any of the HDSCRs at issue. Improperly disregarding the specific aspects of why these tests failed but continuing to make general statements, is the very definition of poor judgment.

Just on this basis alone, the Coyote station "tests" and any conclusions therefrom should be rejected. It is a simple data validation issue. In particular, any conclusions relating to catalyst blinding or plugging etc., which depend on catalyst geometry, from these flawed tests, should definitely be rejected. Knowing these flaws and purposely choosing to ignore them while relying on these tests points to poor technical judgment on the part of the State.

In fact, as the State well knows, the prior Baldwin tests also concluded that HDSCR would not work for those cyclone boilers. Yet, after proper evaluation, the Baldwin station proceeded to install HDSCR and such units have been operating successfully, now for many years. This provides further support for rejection of the Coyote tests.

Finally, several of the SCR and catalyst vendors (Alstom, Babcock Power, CERAM, Halder-Topsoe), who were aware of the Coyote tests, were still willing to provided proper guarantees for HDSCR. The State chose to disregard this.

To the extent that the State is worried about popcorn ash plugging, these issues have been widely and successfully addressed in numerous other HDSCR installations using simple technologies such as ash removal systems (e.g. mechanical screens).

c. Sodium

The State notes that the combustion of North Dakota lignite produces or can produce soluble sodium compounds, which cause more severe catalyst deactivation than insoluble sodium compounds. However, the State fails to show how, under the actual operating temperatures in a HDSCR location, such compounds can penetrate or deposit on the catalyst and if they did so, why they could not be addressed by mitigation measures such as washing (since they are soluble). At least one of the catalyst vendor has noted that "sodium is not a poison to catalyst at SCR operating temperatures..." The critical issue is not whether, as a general matter, sodium can cause deactivation, but whether, under actual operating conditions, it would do so. Without factoring in the operating temperatures, such a statement or concern is meaningless. Since, at the expected operating temperatures, such sodium compounds will generally not condense, this mechanism is speculative and unlikely. At under conditions where such condensation is an issue (such as during shutdown), proper design such as by-pass, can be used. Finally, even if some condensation occurred, it can be mitigated using water washing.

d. Temperature Variations

In some units (such as the Milton Young cyclone unit), the State is concerned that the temperature variation of the flue gas entering a HDSCR will adversely affect its performance. We note that this, again, is a matter of proper design and evaluation. Why there are such large temperature variations and what is causing them are legitimate design issues that need to be resolved on a case-by-case basis. Perhaps additional boiler changes in the backpass, air preheater, or economizer may be needed. But the need for such changes does not eliminate HDSCR. No regulation or guidance contemplates that application of air pollution control technology would be so seamless as to preclude any other changes to the emissions source. To provide this argument in support for technical infeasibility for HDSCR has no merit.

e. Catalyst Erosion

The State is concerned that HDSCR catalysts can erode and that there are "unresolved issues regarding catalyst erosion…." Notwithstanding that all SCR catalysts erode to some extent and that this is accounted for as part of the design of any SCR, the State's position is not substantiated by any data. SCRs have been exposed to bituminous coal combustion ash as high as 40%. Ash contents in coal comparable to that of North Dakota lignite have used SCR for many years.

f. Lack of Vendor Guarantees

The Department states that "vendors cannot without further pilot testing, guarantee SCR system performance for M.R. Young Station boilers firing North Dakota lignite." This statement is simply incorrect as both CERAM and Haldor Topsoe clearly stated, way back in 2007 and 2008, that they would be willing to offer industry standard guarantees for an HDSCR system installed at the Milton R. Young Station, which includes a cyclone boiler. The guarantees that were offered were consistent with those that are typical in the utility industry (i.e., up to contract value), in spite of claims to the contrary by the State and consultants to the utility companies. Making an issue of guarantees in the face of explicit guarantees already being offered by the actual catalyst suppliers underscores the nature and weakness of the State's argument against HDSCR.

In summary, we believe that it is grossly erroneous to conclude the HDSCRs are technically infeasible for any of the utility boilers that are at issue in the RH SIP. For this reason alone, the draft SIP and all of the NO_x limits proposed as BART are flawed and the analysis needs to be redone. In redoing the analysis, the following approach should be followed:

(a) Request engineering quotes for HDSCR systems from experienced SCR and catalyst vendors, capturing up-to-date developments in catalyst design and mitigation strategies for the potential problems that may arise in installation. Determine a range of HDSCR control effectiveness values and associated costs, as appropriate for each unit;

(b) Do the above in a public process so that the problematic and procedural issues inherent in the prior process (in which vendors were essentially brow-beaten by industry consultants) when vendors were contacted, are avoided. Involve U.S. EPA, the National Park Service, and other relevant regulatory agencies in this process;
(c) Lay out clear guidelines for the cost-effectiveness criteria that will be used in a comparison of cost effectiveness of HDSCR. At a minimum, this should include the absolute cost effectiveness expressed as \$/ton NO_x reduced and \$/deciview of visibility improvement (considering all of the unit's impacts at all affected Class I areas). Secondarily, this can include considerations of incremental cost-effectiveness. However, incremental cost-effectiveness is a secondary and not a primary criterion. These guidelines should be clearly stated independently of the HDSCR analysis and should be supported. Some comments on this aspect are provided later.
(d) Conclude whether HDSCR is cost-effective at each unit and therefore whether it is BART or not.

2. TESCR and LDSCR Are Cost Effective.

As noted above, in rejecting HDSCR, we believe that the State has fatally compromised its NO_x BART analysis and, therefore, the analysis should be redone.

Separately from that, although the State did require that TESCR and LDSCR be considered since they are technically feasible (after incorrectly arguing that they are not for years), these technologies were rejected on cost-effectiveness grounds. We believe that this rejection was in error for the following reasons:

(a) A lack of transparency of how the costs were developed. In no case were detailed cost-estimates provided in the record, along with the associated design of the SCRs. Rather, gross values of SCR in \$/kW terms were assumed along with numerous other assumptions, stated and unstated. Without this information, there is insufficient data for analysis of cost effectiveness by the public or any agency. The SIP should be considered incomplete without this information. Thus, the cost figures arrived at (and the associated control efficiencies) are unreliable and are assumed to be higher than actual.
(b) An incorrect reliance on incremental cost-effectiveness as the metric for cost effectiveness;
(c) A lack of stated and defensible cost-effectiveness metrics by the State.

We believe that higher values of total (not incremental) cost-effectiveness are appropriate. Higher measures of cost-effectiveness than those used by the State have been used in both BART analyses and rule-making instances, over \$10,000/ton in some instances.[47] As

[47] See National Park Service Spreadsheet "EGUs with Proposed BART NOx Controls" and "EGUs with Proposed BART SO2 Controls" dated November 13, 2009, Ex. 32 and Ex. 18, demonstrating BART determinations at cost effectiveness up to \$7,309/ton (SO2) and \$3,778/ton (NOx); \$10,000/ton was determined to be cost effective for BACT in 2001, equivalent to over \$13,000/ton today. *See* expert report of Matt Haber - EPA, *Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois*, prepared for the United States in connection with United States v. Illinois Power Company and Dynegy Midwest Generation, Inc., Civil Action 99-883-MJR, in the U.S. District Court for the Southern District of Illinois, April 2002, p. 17, Ex. 16; Memorandum of John S. Seitz

noted by EPA itself in its comments in the present instance, there is no justification to limit the cost-effectiveness to just those values considered in the examples of presumptive-BART, as has been done by the utilities and the State.

Considering a higher range of cost-effectiveness, the application of TESCR and/or LDSCR is cost-effective in many cases in the instances where considered. This is in spite of the lack of transparency in the costs themselves as noted above. In other cases where it is not cost-effective at this metric, we stand by our comment on the lack of transparency. We also note that at this level of cost-effectiveness, other NO_x control technologies that were incorrectly rejected (such as SNCR) are also cost-effective.

Thus, there is no justification for rejecting TESCR or LDSCR as NO_x BART. Therefore, the proposed BART limits are flawed and the analysis should be rejected.

3. Specific Comments on Each NO_x BART Analysis

Our additional comments on the seven specific BART utility boilers NO_x BART analyses are noted below. However, these are not extensive in view of the lack of time provided for public comment. The brevity of these comments should not be interpreted as an indicator of agreement with the analyses or the conclusions presented in the proposed RH SIP. As such, we stand by comments made by others including the U.S. EPA in specific instances, particularly as related to the incorrect assumptions in the design and cost analyses present by industry consultants including Sargent and Lundy.

<u>Basin Electric Power Cooperative Leland Olds Station Unit 1</u> - This unit is a wall-fired pulverized coal boiler combusting primarily lignite coal (80-100%) and PRB subbituminous coal (20-0%). The existing nitrogen oxides control equipment is low NO_x burners installed in 1995. The BART selected by the State is a limit of 0.19 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the installation of selective noncatalytic reduction (SNCR) and basic separated overfire air (SOFA). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that LDSCR with reheat that was considered in the analysis was improperly rejected given that its cost-effectiveness, as calculated with non-transparent cost data, was in line with the range of other cost-effectiveness decisions.

<u>Basin Electric Power Cooperative Leland Olds Station Unit 2</u> - This unit is a cyclone boiler combusting primarily lignite coal (80-100%) and PRB subbituminous coal (20-0%). The unit has no existing nitrogen oxides control equipment. The BART selected by the State is a limit of 0.35 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the installation of selective noncatalytic reduction (SNCR) and advanced separated overfire air (ASOFA). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. As noted above for Unit 1 for this station, LDSCR was improperly rejected as BART based on erroneous cost criteria.

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to Air Division Directors, BACT and LAER for emissions of nitrogen oxides and volatile organic compounds at Tier 2/Gasoline Sulfur Refinery Projects (Jan. 19, 2001), at 3, Ex. 17.

Great River Energy Coal Creek Station Unit 1 and Unit 2 - Unit 1 and Unit 2 are identical tangentially-fired pulverized coal boilers combusting lignite coal. The existing nitrogen oxides control equipment is low NO_x burners (LNB) and separated overfire air (SOFA). The BART selected by the Department for each unit is a limit of 0.17 pounds per million Btu of heat input on a 30-day rolling average basis. This limit is to be achieved by the use of the existing low NO_x burners (LNB) and modified/additional separated overfire air (SOFA). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that an improper value (80%) was used as the control efficiency for LDSCR, resulting in an erroneously high cost-effectiveness for LDSCR.

Great River Energy Stanton Station Unit 1 - Unit 1 is a wall-fired pulverized coal boiler combusting PRB subbituminous coal and lignite coal. The existing nitrogen oxides control equipment is low NO_x burners. The BART selected by the State is a limit of 0.29 pounds per million Btu of heat input on a 30-day rolling average basis when burning only lignite coal, a limit of 0.23 pounds per million Btu of heat input on a 30-day rolling average basis when burning subbituminous coal, and a weighted average emission limit when burning a combination of lignite and subbituminous coal. These limits are to be achieved by the installation of low NO_x burners (LNB), overfire air (OFA), and selective noncatalytic reduction (SNCR). We believe that these technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that LDSCR, which was considered technically feasible, was improperly rejected given its cost-effectiveness of $6,475 is in the range of appropriate cost-effectiveness values.

Minnkota Power Cooperative Milton R. Young Station Unit 1 and Unit 2 - Unit 1 and Unit 2 are both cyclone boilers burning lignite coal. The units have no existing nitrogen oxides control equipment. The BART selected by the State for Unit 1 is a limit of 0.36 pounds per million Btu of heat input on a 30-day rolling average basis and for Unit 2 is a limit of 0.35 pounds per million Btu of heat input on a 30-day rolling average basis. These limits will be achieved by the installation of selective noncatalytic reduction (SNCR) and advanced separated overfire air (ASOFA). These technologies and the limits contained in the draft SIP are identical to the provisions in the consent decree. The State has done nothing more than take what has already been required by law and rolled that into the BART analysis. We believe that this does not constitute an adequate BART analysis.

Specifically, we believe that the selected technologies do not constitute BART and that HDSCR was improperly rejected in the analysis. We also believe that LDSCR and TESCR, which were considered technically feasible, were improperly rejected given cost-effectiveness values of $3,906/$5,591 (LDSCR) and $4,835/$6,266 (TESCR) for Unit 1 and $4291/$6382 (LDSCR) and $4,948/$7081 (TESCR) for Unit 2 are in the range of appropriate cost-effectiveness values.

II. NDDH Has Failed to Include Other Emission Reduction Requirements as Part of Its Long Term Strategy to Meet Reasonable Progress Requirements Which Must Be Designed to Meet the Goal of Natural Visibility Conditions by 2064

Although NDDH evaluated additional controls at Antelope Valley Units 1 and 2, Coyote Station, the Great Plains SynFuel Plant, and the Tioga Gas Plant, NDDH did not ultimately propose any additional emission reductions as part of its long term strategy to meet reasonable progress goals. NDDH placed heavy focus on these additional controls based on costs, and NDDH discounted all additional controls at these facilities due to its determination of a limited visibility benefit to be gained from the controls. Draft North Dakota SIP for Regional Haze at 185.

NDDH has not adequately met the regional haze requirements of developing a long term strategy to show how it would meet reasonable progress goals to attain natural visibility conditions by 2064, as required by 40 C.F.R. §51.308(d)(1) and (d)(3). First, NDDH should not have limited its analysis of additional measures to provide for reasonable progress to facilities not already controlled by BART. As shown above, NDDH's proposed BART emission limits and requirements do not reflect the maximum emission reductions that could be achieved at the State's EGUs. For those controls or more stringent control efficiencies that NDDH determines are not required to meet BART, NDDH must still evaluate use of those control technologies and/or methods as part of its long term strategy to meet reasonable progress goals. For example, if NDDH determined SCR is not BART for an EGU, it could still require SCR at that EGU to meet reasonable progress requirements. Further, NDDH also excluded the Heskett EGU from evaluation of long term strategy requirements. While NDDH postponed a determination of whether Heskett was subject to BART, that should not exclude the unit from evaluation of pollution controls as part of the State's long term strategy.

Second, in evaluating additional control measures to meet the national visibility goal, NDDH should not just place emphasis on the benefit to visibility achieved by the reductions at each emissions unit. Instead, NDDH should evaluate the cumulative effective of the State's strategy to meet reasonable progress goals to attain natural visibility conditions by 2064. 40 C.F.R. §51.308(d)(3)(iv)(G).

Further, 40 C.F.R. §51.302(d)(3)(ii) provides:

> Where other States cause or contribute to impairment in a mandatory Class I Federal area, *the State must demonstrate that it has included in its implementation plan all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area.*

[Emphasis added.]

Thus, NDDH must evaluate all available measure to reduce North Dakota's share of visibility impairing pollution as part of its long term strategy. Such available measures include emission reduction programs, imposition of emission limitations, and source retirement and replacements.

NDDH did not evaluate the potential for any EGU retirements in its draft regional haze SIP. Given the age of the State's coal-fired EGUs along with the fact that North Dakota's draft SIP falls far short of meeting reasonable progress goals for regional haze, NDDH must consider EGU retirements to meet reasonable progress goals as part of its long term strategy.

For the sources for which NDDH did evaluate controls, it did not evaluate the most stringent levels of control achievable. For example, for Antelope Valley Units 1 and 2, NDDH only evaluated a wet scrubber that could achieve 95% SO_2 removal even though, as we have shown above, wet scrubbers can achieve 98-99% SO_2 removal. Further, NDDH did not conduct any modeling to show the visibility improvement from use of a wet scrubber at the Antelope Valley units because it found the costs to be too high. As shown in the National Park Service SO_2 BART Summary spreadsheet (Ex. 11), the costs of wet scrubbers at Antelope Valley Units 1 and 2 ($5,899-$6,780/ton) are not out of the range of SO_2 BART control costs. A new wet scrubber at the Coyote Station is quite cost effective at $2,593/ton.

Even if the costs were more than previously required as BART, that should not be a reason alone to discount use of a control technology. This is especially true with North Dakota's regional haze SIP which fails to meet the uniform rate of progress necessary to attain natural visibility conditions by 2064. Further, given the fact that North Dakota sources cause and contribute to visibility impairment in other states, it is imperative that NDDH include <u>all</u> emission reduction measures in its long term strategy to meet reasonable progress goals. While it is true there will be costs to reducing visibility impairing pollution from North Dakota sources, such costs do not allow North Dakota to ignore the national visibility goal of the Clean Air Act and the requirements for regional haze SIPs. Thus, cost of controls alone should not be a determining factor in evaluating additional emission reduction options in the State's long term strategy. Accordingly, NDDH should evaluate the use of SCR at units such as Antelope Valley and Coyote, as well as at those EGUs for which NDDH determines SCR is not BART, for inclusion in its long term strategy.

In summary, North Dakota's draft SIP for regional haze fails to include adequate reasonable progress goals and fails to include an adequate long term strategy to meet reasonable progress goals. While North Dakota's proposed BART determinations will greatly reduce SO_2 emissions and, to a lesser extent, NO_x emissions from the State's BART-eligible EGUs, the State's plan does not go far enough to ensure that North Dakota's Class I areas and the Class I areas in other states that are impacted by North Dakota sources will achieve natural visibility conditions by 2064. Thus, North Dakota must adopt additional measures or requirements, including consideration of source retirements, as part of its long term strategy to achieve reasonable progress toward the national visibility goal.

III. North Dakota Must Also Propose Short Term Average Emission Limits on SO_2 Emissions in Order to Ensure Protection of the SO_2 Increments of the State's Class I Areas

The SO_2 emission reductions that North Dakota has proposed as BART for the State's BART-eligible EGUs should greatly help the State address the SO_2 increment violations that have been occurring at the North Dakota Class I areas.[48] And we recently learned that the State

[48] See 5/24/99 North Dakota Class I Area Calpuff Analysis; see also 5/8/03 EPA Dispersion Modeling Analysis.

has issued a draft plan for updating and evaluating a new modeling protocol and that the State plans on conducting a new periodic assessment of increment consumption in the near future.[49] However, in order for the State to be able to count on the SO_2 emission reductions proposed to meet BART in its new periodic assessment of SO_2 increment consumption or in other increment modeling analyses (such as those conducted for PSD permits), NDDH must propose for public comment short term average emission limits in addition to the 30-day average BART emission limits for the State's EGUs that are installing pollution controls. A long term average limit does not ensure 3-hour average or 24-hour average emissions will be reduced to the same levels, especially given that NDDH's proposed SO_2 BART limits are based on worst case sulfur content assumptions that are not reflective of the coal the units are currently burning.

The visibility protection program falls under the same part of the Clean Air Act that the increments do – that is, the prevention of significant deterioration program of Part C of the Clean Air Act. One of the mandates of the prevention of significant deterioration program is to preserve, protect, and enhance the air quality in national parks and wilderness Class I areas. CAA §160(2). For Class I areas, the Clean Air Act provides protection for Class I areas by requiring compliance with stringent PSD increments *and* by requiring protection of air quality related values including visibility. CAA §§162, 165(d), and 169A.

Because air quality modeling analyses that comply with EPA policies for increment consumption have shown that violations of the 3-hour and 24-hour average SO_2 increment are occurring in the State's Class I areas, it is imperative that North Dakota harmonize the SO_2 emission reductions that the State is requiring as part of its regional haze SIP with the requirement for the State's Class I areas to comply with the 3-hour and 24-hour average SO_2 increments. Thus, North Dakota must impose short term average SO_2 emission limits reflective of the SO_2 controls and emission reductions being required in its draft regional haze plan (primarily through BART) in order to be able to rely on the emission reductions in analyses of compliance with the 3-hour and 24-hour average SO_2 Class I increments.

Such emission limits must be reflective of the capabilities of the SO_2 controls being installed, in order to be consistent with the general purpose of the North Dakota regulations to "state such requirements as shall be required to achieve and maintain the best air quality possible, consistent with the best available control technology… and to facilitate the enjoyment of the natural attractions of this state." ND Reg. 33-15-01-01. The definition of "best available control technology" under the State's PSD regulations is defined as an emission limitation "based on the maximum degree of reduction" of a pollutant that is achievable. ND Reg. 33-15-15-01.2 incorporating by reference 40 C.F.R. 52.21(b)(12). And "emission limitation" is defined under the Clean Air Act as a requirement established by a state or EPA which limits emissions "on a continuous basis." CAA §302(k). Thus, in establishing short term average emission limits that can be relied upon in analyses of compliance with the PSD increments, North Dakota must set limits consistent with the maximum degree of emission reductions that is achievable with the BART SO_2 controls and that reflect operation of the SO_2 controls on a continuous basis. Without such short term average emission limits, NDDH cannot rely on the planned SO_2

[49] As discussed in NDDH's "A Plan for Updating and Testing the North Dakota Department of Health's CALMET and CALPUFF Protocol," Draft Final, December 29, 2009, available at http://www.ndhealth.gov/AQ/NoticesPSDStatusIncrementConsumption.htm.

reductions at the State's EGUs in any increment analyses until the BART controls have been installed and normal operation has resumed for at least two years.

As we stated above, we understand from the NDDH's draft plan to revise the State's modeling protocol that the State plans to conduct a new periodic assessment of SO_2 increment consumption soon. Not only is such an analysis required under 40 C.F.R. §51.166(a)(4), but a new analysis is also required because, in its previous assessment of increment consumption, NDDH relied on techniques and methods that are inconsistent with EPA policy and the intent of the Clean Air Act. Although EPA proposed revisions to its regulations that would have allowed for many of North Dakota's increment modeling techniques and approaches[50], EPA never finalized that rulemaking and has indicated it will not finalize that rulemaking. Therefore, North Dakota cannot rely on those techniques and approaches that are inconsistent with EPA policy and with the intent of the PSD program of the Clean Air Act in evaluating increment consumption. Because prior analyses by NDDH (in 1999) and by EPA (in 2003) that more closely complied with EPA policy showed numerous violations of the 3-hour and 24-hour SO_2 increments in the State's Class I areas, it is imperative that NDDH conduct a new assessment of SO_2 increment consumption following EPA policy and consistent with the PSD mandates of the Clean Air Act. And, for NDDH to rely on the BART SO_2 reductions in such an analysis, the State must propose and adopt short term average emission limits.

IV. Other General Comments

1. The proposed RH SIP notes that the visibility monitor (IMPROVE THRO1 monitor) is located at the Painted Canyon Overlook in the South Unit of Theodore Roosevelt National Park. It also notes that this one monitor is "representative" of haze conditions in the separate North Unit and the separate Elkhorn Ranch Unit of the THRO Park. However, why and how a single monitor can be or is representative of haze conditions at these other, distant locations is never discussed. We believe that without technical support, the assumption that THRO1 is representative of conditions elsewhere in the THRO are unsupported. It is not enough to simply assert that this one monitor is representative, without basis (see page 31 of the proposed RH SIP). To the extent that the RH SIP relies on this TR-North Unit and TR-Elkhorn Ranch Unit. This is a fundamental flaw of the analysis.[51]

2. The RH SIP does not provide the details of its calculations for baseline visibility including all input assumptions. Thus, the values used cannot be verified. This is especially important since the values used are greater than EPA recommended values.

3. The proposed SIP (page 68) notes that "The FLMs and EPA have expressed concerns about the modeling that was conducted. MDU has agreed to remodel using a revised

[50] 72 Fed.Reg. 31372, June 6, 2007.

[51] This critique is not in conflict with our support for treating THRO as it was designated: one mandatory Class I area, not three. In this case, THRO is one Class I area spread out over significant distance, and multiple monitors are appropriate in the same way that they would be for one large contiguous Class I area (e.g. Yellowstone National Park).

modeling protocol. The Department will reassess the determination to exclude Heskett Station Unit 2 following review of the revised modeling. Heskett Unit 2 will be addressed in a supplement to this SIP revision." This analysis cannot be put off to the future and must be part of the regional haze plan. Without this analysis, the SIP is incomplete. In the alternate, if the Heskett analysis is not now included, the supplement should be subject to full public review.

Thank you for the opportunity to comment on the draft Regional Haze State Implementation Plan.

Sincerely,

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EPA Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility

US Environmental Protection Agency Region 9

July 31, 2008

c. **Comment:** Further, 98% is not the highest achievable SO_2 control efficiency for low sulfur coal similar to Navajo's coal. The

Application and AAQIR rely on other permitted sources, corrupting the BACT process. Many other sources of information, other than just permitted levels, must be consulted to determine BACT...The top control option is a wet FGD designed to achieve 99%+ SO_2 control. This level of control has been achieved at the Mitchell Station in Pennsylvania using magnesium enhanced lime, a type of wet FGD...It has also been achieved at several coal-fired power plants in Japan and is proposed for several U.S. coal fired power plants.

Chiyoda's bubbling jet reactor (a type of wet FGD) has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level while treating gases with inlet SO_2 concentrations within the range proposed for DREF (1.78 lb SO_2/MMBtu compared to 1.84 lb SO_2/MMBtu for DREF). This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan. It also has been demonstrated in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates and recently was licensed for use on several additional plants in the US, including Plant Bowen in Georgia, Dayton Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others. Black & Veatch and Southern Company are both U.S. licensees.

Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including four coal-fired boilers.

Finally, a recent Lake Michigan Air Directors Consortium ("LADCO") and the Midwest Regional Planning Organization ("MRPO") presentation indicated that advanced FGD technologies could achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removed and wet FGD could achieve 99% SO_2 control for $1,881 to $3,440 per ton of SO_2 removed. [23]

Response: With respect to the claims that EPA's and the Applicant's reliance on other permitted sources has corrupted the BACT process and that higher levels of control have been achieved at other sources, the commenters are first referred to the responses to comments II.C.1.e and II.C.1.g. A BACT determination involves judgment and balancing, and does not involve simply picking the lowest numerical emission limit or the highest observed control efficiency. The design of wet a FGD system and the resulting control efficiency depends on a variety of parameters, including the characteristics of the fuel, boiler operating data and tolerances, emission requirements (not only for SO_2 but also for particulate, dust, temperature, and waste water), limestone availability and quality, and economic factors.[3] As discussed in the permit application, a comparison of relative control efficiencies of add-on SO_2 control equipment must take into account the amount of uncontrolled SO_2 to be treated. For example, for a given heat input, a facility with a BACT limit of 0.06 lb/MMBtu that achieves 95% control will result in fewer emissions to the atmosphere than a facility with a limit of 0.1 lb/MMBtu that achieves 98% control. It is therefore misleading for the commenters to cite to other facilities that achieve greater control efficiencies than proposed for the DREF while ignoring differences in site specific factors.

Moving to the commenters' specific claims, the commenters first assert that the Mitchell Power Station in Courtney, PA has achieved greater than 99% SO_2 control. In support of the statement, the commenters submitted data which purportedly represents daily emissions from the facility.[4] The commenters' assertion is misleading because the information submitted contains only 88 days worth of monitoring data collected over a span of 17 months between July 1983 and December 1984. As previously discussed, the EAB has recognized the distinction between measured emissions data at one point in time and an emissions limitation placed into a PSD permit which must be met continuously for the entire life of the facility. Actual emissions data reported by the facility pursuant to the Acid Rain program reveal that the emissions are much higher in recent years than they were for the brief period from 1983-1984. The following statistics reflect actual SO_2 emissions from the Mitchell Power Station in 2006:[5]

Total Number of Days Monitored:	312
Lowest Daily Average Emission Rate:	0.01 lb/MMBtu
Highest Daily Average Emission Rate:	0.36 lb/MMBtu
Frequency Analysis	
Range	**Number of Days**
$X \leq 0.06$ lb/MMBtu	29

[3] See *Alstom Environmental Control Systems Wet FGD Design Criteria*, included as Attachment 2.
[4] The data submitted by the commenters is on plain paper with no markings or other indications whatsoever that it represents the actual emissions from this facility. However, for the sake of the comment, EPA will consider the data to be legitimate.
[5] The facility had several startups, shutdowns, and process upsets in 2006. Emissions data from these periods were generally higher than for normal operations and were excluded from the statistical review. The raw data from EPA's Clean Air Markets database is included in Attachment 3.

0.07 lb/MMBtu $\leq X \leq$ 0.09 lb/MMBtu	125
0.10 lb/MMBtu $\leq X \leq$ 0.19 lb/MMBtu	138
0.20 lb/MMBtu $\leq X \leq$ 0.29 lb/MMBtu	16
0.30 lb/MMBtu $\leq X \leq$ 0.39 lb/MMBtu	4

It is clear from this data that the Mitchell Power Station has achieved a daily average emission rate equal to or less than the limit proposed for the DREF for only 29 days out of the year. The actual emissions were moderately higher for the remainder of the year. By comparison, the DREF would never be allowed to exceed 0.060 lb/MMBtu over a 24-hour average and would thus perform far better than the Mitchell Power Station on a heat input basis. Thus EPA does not agree with the commenters that the Mitchell Power Station provides evidence that the proposed DREF limit is not BACT.

The commenters' next claim that the Chiyoda's bubbling jet reactor has consistently achieved greater than 99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan and that it has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan. In support of its claim regarding the three boilers in Japan, the commenters referred to a website operated by Burmeister & Wain Energy, which has the license for the CT-121 FGD process on the European market. This site contains two promotional documents. The first document, *CT-121 FGD Process* (included as Attachment 4), contains an elementary description of the CT-121 process and its purported advantages, including a generic statement that removal efficiencies up to 99%+ are possible. It does not, however, provide any technical information regarding the conditions under which such efficiencies can be achieved nor does it provide any information about actual guaranteed emission rates (see earlier discussion regarding comparison of control efficiencies versus actual emission rates). The second document, *Flue Gas Desulphurization Reference list CT-121*(included as Attachment 5), is simply a list of facilities in which the CT-121 process has been or will be installed, the installation dates, and the SO_2 control efficiencies, which range from 82% to 99%. This list clearly shows that this technology has a wide range of efficiencies and as with the first document, it provides no information about the conditions under which the higher efficiencies can be achieved nor does it state what the guaranteed emission rates are for the facilities that are achieving high removal efficiencies. It is also worth noting that many of the facilities in the list with higher control efficiencies are not in operation as the dates provided in the table are 2008 and beyond. The lack of any useful technical information in these documents provides EPA with no basis for a more detailed response. The commenters did cite to one technical paper by Yasuhiko Shimogama and others. Though this paper indicates that 99% control is being achieved at the Shinko-Kobe plant, EPA can not rely on this document alone to establish BACT. Other pertinent information such as the permitted emission limits, averaging periods, and actual emissions data should be submitted. It is the commenters' burden to provide that information and the commenters have failed to meet that burden in this case. Nonetheless, EPA attempted to contact the Japan Ministry of the Environment for additional information but to date, our request for information has not been answered. EPA did, however, receive a response to a request for information from Kobe Steel, Ltd., the company that owns and operates the Shinko-Kobe plant. Specifically, EPA asked about Kobe Steel's general experience using the technology. In his reply, the manager of the Power Plant Technology Section stated that the SO_2 removal efficiency has never dropped below the guaranteed performance level, that their experience with the CT-121 process has been positive, and that their decision to use the CT-121 at that plant was the correct one. However, they also noted that they have been experiencing problems with the system's sulfur gas fan. Specifically, they have been experiencing degradation of fan efficiency by gypsum deposits during normal operation of the plant. They stated that an attempt has been made to remedy the problem by installing a washing system but that has not been sufficient and the problem still remains unresolved by the supplier. As a result, they are required to conduct periodic preventive maintenance every two to three months. During a planned outage over a weekend, they stop plant operations for two days and wash the fan blades. See Attachment 6, *July 31, 2007 e-mail from Gary Tsuchida*. EPA does not believe it is reasonable to require the use of a technology with unresolved operational issues that require such frequent shutdowns of the plant. Thus while the technology appears promising for certain situations, it may not be suitable for all situations and EPA cannot simply require its use in every instance. As the commenters later note in their comments, this technology is being planned for use at other plants. Those installations will likely provide additional data and operating experience that does not currently exist but that is needed to fully evaluate this technology in future BACT analyses.

The commenters also claim that Chiyoda's bubbling jet reactor has been demonstrated in the U.S. at the University of Illinois's Abbott power plant and Georgia Power's Plant Yates and recently was licensed for use on several additional plants in the US, including Plant Bowen in Georgia, Dayton Power & Light's Killen and Stuart plants, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek.

The commenters are correct that the Chiyoda's CT-121 FGD system is used at the University of Illinois's Abbott Power Plant and Georgia Power's Plant Yates. However, a review of the actual emissions data from these facilities again demonstrates that the DREF would have lower emissions than these facilities on a heat input basis. The following statistics reflect actual SO_2 emissions data from Plant Yates in 2006. The raw data from the Clean Air Markets database is included in Attachment 7

Total Number of Days Monitored:	346
Lowest Daily Average Emission Rate:	0.02 lb/MMBtu
Highest Daily Average Emission Rate:	0.38 lb/MMBtu

Frequency Analysis	
Range	**Number of Days**
X ≤ 0.06 lb/MMBtu	48
0.07 lb/MMBtu ≤ X ≤ 0.09 lb/MMBtu	28
0.10 lb/MMBtu ≤ X ≤ 0.19 lb/MMBtu	140
0.20 lb/MMBtu ≤ X ≤ 0.29 lb/MMBtu	97
0.30 lb/MMBtu ≤ X ≤ 0.39 lb/MMBtu	33

It is again clear from this data that while Plant Yates has achieved a daily average emission rate equal to or less than the limit proposed for the DREF for short periods of time, for the majority of the time the emission rates were significantly higher. Furthermore, information obtained from the Illinois Environmental Protection Agency (IEPA) shows that the actual measured control efficiency of the FGD system at the Abbott Power Plant is 92.3%. See Attachment 8, *6/14/2007 fax from Joe Kotas*, IEPA. In addition, the Abbott Power Plant includes three boilers of approximately 200 MW each. To the extent that boiler characteristics affect emissions and control technology design, these units do not serve as a good reference for the DREF, which has much larger units. EPA thus disagrees with the commenters that the use of Chiyoda's equipment at another facility is an indication the proposed limit for the DREF is not BACT.

The commenters are also correct that Chiyoda's FGD system is being installed on several other plants. However, most of those referred to by the commenters are not yet constructed or operating. According to the Kentucky Department for Environmental Protection, Division for Air Quality, the Big Sandy project has been postponed until 2014; it is thus not useful for establishing BACT for the DREF. See Attachment 9, *e-mail from Candy Montgomery, Kentucky DAQ*, June 8, 2007. The Conesville, Cardinal and Kyger

Creek projects are proceeding but are currently in various stages of construction. According to the Ohio EPA, the control efficiency for these systems is estimated at 98%. However, even with 98% control, the emission limits (in terms of lb/MMBtu heat input) for these facilities will be significantly higher than the proposed limit for the DREF, further supporting EPA's conclusion that the DREF limit represents BACT. The current status of these facilities and their emission limits are summarized in the following table:

Facility/Unit	Stage of Construction	Emission Limit
AEP Conesville #4	Early stage of construction	0.90 lb/MMBtu (30-day rolling average)
AEP Muskingum River #5	Construction halted	1.5 lb/MMBtu (30-day rolling average)
AEP Kygèr Creek Units 1-5	Early stages of construction	1.20 lb/MMBtu (30-day rolling average)
AEP Cardinal Units 1&2	Construction nearing completion	2.5 lb/MMBtu (30-day rolling average)

See Attachment 10, *e-mail from Dean Ponchak*, Ohio EPA, June 8, 2007. The emission limits for Dayton Power & Light's Killen and Stuart plants are similarly higher than the DREF limit:

Facility/Unit	Emission Limit
Killen Station #2	1.2 lb/MMBtu
Stuart Unit #4	1.77 lb/MMBtu (30-day average)
Stuart Unit #3	1.77 lb/MMBtu (30-day average)
Stuart Unit #1	1.77 lb/MMBtu (30-day average)
Stuart Unit #2	1.77 lb/MMBtu (30-day average)

See Attachment 11, *e-mail from Cindy Charles*, Ohio EPA, June 8, 2007. FGD systems on Units 1-4 at Plant Bowen are also in the construction phase. However, these systems are being installed for purposes of compliance with the Clean Air Interstate Rule and at the time this document was written the facility has not yet received its allocation. Until the allocations are received, the permits to install these systems have no emission limits or other operating requirements.

The commenters further claim that Mitsubishi reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including four coal-fired boilers. The commenters are again misleading in their statements because they point to control efficiencies without respect to inlet pollutant loading. In support of their statements, the commenters refer to two technical papers and a page on Mitsubishi Heavy Industries' website. Both technical papers explicitly state that the highest SO_2 control efficiencies are associated with high inlet SO_2 concentrations:

> In this paper, performance test data for the latest single-tower coal-fired application (a 600MW module) that started commercial operation on July 12, 2004 are reported. In addition, **super high SO_2 removal efficiency (99-99.9%) <u>under high inlet SO_2 conditions</u>** (2,000-3,000ppm) achieved by a single DCFS module and an extraordinary space-saving design related to its compactness feature are also introduced here...
>
> Nakayama et. al. at 1 (emphasis added).

> The twin tower design, which is the combination of co- and counter-current designs, is selected when both high particulate removal and **extremely high desulfurization performance requirement (98% and over) <u>for high sulfur coal</u>** are required...In the past 2 or 3 years, we have been successful in achieving **ultra-high SO_2 removal efficiency (e.g., 99.9%) <u>with a high inlet SO_2</u>** using a single tower DCFS.
>
> Nakayama et. al. at 2 (emphasis added).

> This paper provides a detailed description of the DCFS FGD system including operating data from recent installations...Recent operating experience is reviewed in detail. In particular, the paper highlights design requirements to achieve **SO_2 removal efficiencies as high as 99.9 percent <u>on high sulfur coals</u>**.
>
> Klingspor et. al. at 1 (emphasis added).

High inlet concentrations tend to make high removal efficiencies more practical and economical. Also, as previously discussed, having the lowest emission rate on a heat input basis does not necessarily require achieving the highest control efficiency if the use of low-sulfur coal results in lower uncontrolled emissions to begin with. EPA thus remains convinced that the proposed limit represents BACT in this instance.

Finally, the commenters note that a recent Lake Michigan Air Directors Consortium (LADCO) and Midwest Regional Planning Organization (MRPO) presentation indicated that advanced FGD technologies could achieve 99.5% control for $1,240 to $2,875 per ton of SO_2 removed and wet FGD could achieve 99% SO_2 control for $1,881 to $3,440 per ton of SO_2 removed. According to the engineering analysis for boilers referenced in the presentation, the cost estimates referred to by the commenters were developed assuming a fuel sulfur content of 2.5%. This is 2-3 times higher than the sulfur content of the coal to be used at the DREF and thus the LADCO example does not necessarily reflect the true economics for this or other facilities that use low sulfur coal. Furthermore, the LADCO report cautions that these estimates are intended to provide a general indication of the technical and economic feasibility of each control technology and that a unit-specific evaluation must still be performed. The report further recognizes the likelihood that site-specific vendor quotes will be required to get accurate cost analysis results. See Attachment 12, *LADCO Report* at 20.

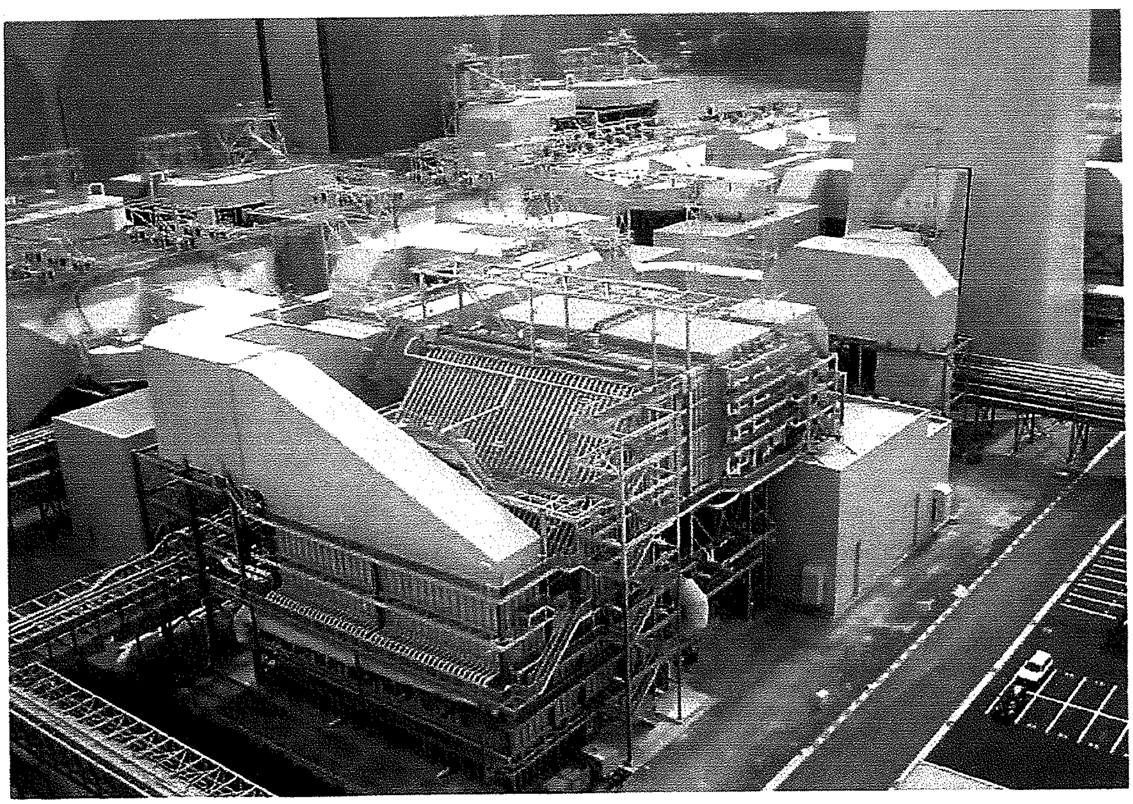
d. **Comment:** Japan regulates SO_2 emissions to about 10 ppm (0.02 lb/MMBtu) from new industrial facilities locating in polluted areas. There are currently two Japanese vendors who supply wet FGD systems in the U.S. market that are able to achieve 99% SO_2 control on low sulfur coals. These are Chiyoda and Mitsubishi, as discussed supra. These two wet FGD systems are more cost effective, require less water and electricity, generate less wastes, and remove more mercury and particulate matter than the type of wet FGD selected for DREF. They do not have any adverse energy, environmental, or economic impacts.

This Japanese experience is supported by two facilities in the U.S. The U.S. EPA issued a PSD permit to AES Puerto Rico to construct and operate a 454-MW coal-fired CFB project. The permit requires the unit to meet an SO_2 limit of 0.022 lb/MMBtu or 9.00 ppmvd corrected to 7% oxygen on a 3-hour basis, compared to 0.09lb/MMBtu on a 3-hour basis and 0.06 lb/MMBtu on a 24-hour basis for DREF. The much lower AES Puerto Rico limit has been achieved. Further, Utah issued a permit for the Nevco Sevier project in October 2004. Its SO_2 limits are: 0.022 lb/MMBtu based on a 30-day average and 0.05 lb/MMBtu based on a 24-hour average. We are not advocating CFBs for DREF, but rather that the emission limits proposed for these CFB units should be included in the top down BACT analysis for PC boilers, as set out below. [23]

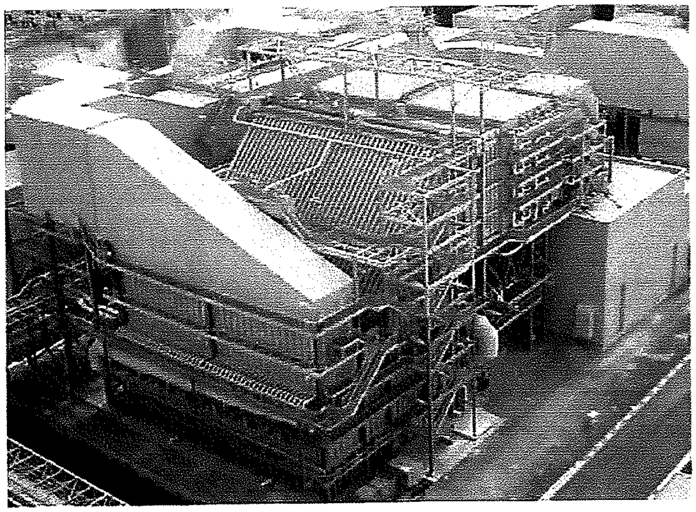
ADVATECH™

A company of URS and MHIA

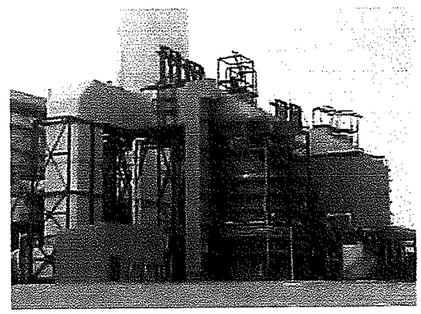
Advanced
Flue Gas Desulfurization



The Next Generation



The EPDC Tachibanawan Power Station has a single 1,050 MWe DCFS module that is the largest FGD module in the world. The unit has operated at 100 percent availability since startup in 2000. The SO_2 removal is in excess of 95 percent and can be tuned for greater removal by optimizing recycle pump operation.



The twin tower DCFS FGD system installed at the Rathaburi Power Station in Thailand operates at 97 percent SO_2 removal efficiency.

The plant is designed with close-coupled gas-to-gas regenerative reheat located on top of the absorber.

Unrivaled Experience

Highlights of Our Worldwide FGD Experience

Installed FGD Capacity	~56,000 MWe
FGD Orders Last 10 Years	~30,000 MWe
Highest SO_2 Guaranteed Removal	99.80%
Highest SO_2 Removal w/o Additives	99.90%
Highest SO_2 Concentration	7,800 ppm
Largest Single Absorber	1,060 MWe
Longest Time Between Outages	2 yrs
Spare Modules Installed	None
Highest Availability, Single Module	100% / 12yrs

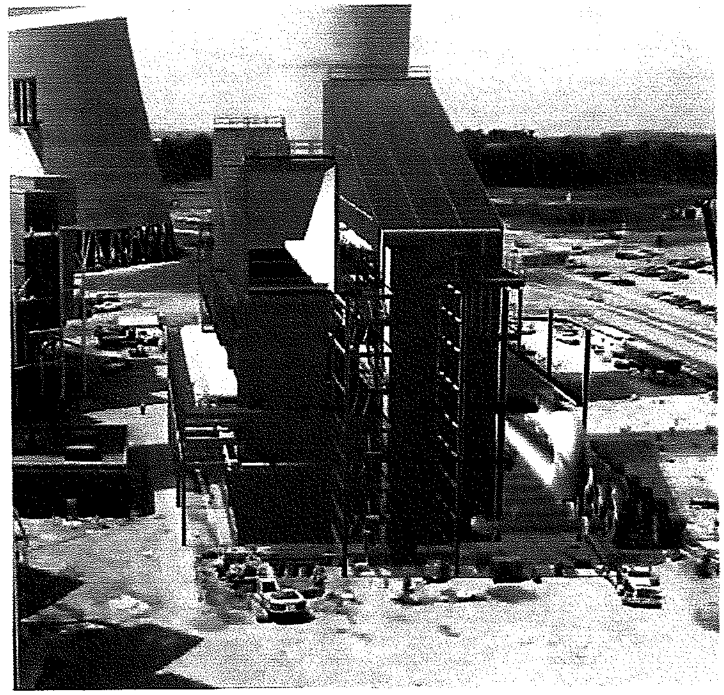
Advatech was formed jointly by URS and Mitsubishi Heavy Industries America (MHIA) to provide flue gas desulfurization (FGD) systems to American utilities. Advatech combines the Mitsubishi Heavy Industries (MHI) Double Contact Flow Scrubber (DCFS) advanced FGD technology and the comprehensive engineering, procurement, and project implementation services of URS.

Through Advatech, URS and MHIA bring unsurpassed technology, engineering, design, procurement and project implementation services backed by strong parent companies. Radian Corporation, now a part of URS, began offering FGD services over 30 years ago.

The first MHI FGD system was installed in 1964. Today, MHI is the world's leading supplier of FGD systems with over 56,000 MWe installed on more than 160 boilers in 14 countries.

Available in the US through Advatech, the DCFS system is highly reliable, and the uniqueness of its design allows it to operate at 100 percent availability with no spare

Advatech is currently designing a single-module DCFS FGD system for Alabama Power's 1,151 MWe Plant Gorgas which will achieve 98 percent SO_2 removal efficiency with ultra-high reliability.



The twin-tower DCFS FGD system currently being installed at the Paradise Power Station will be the largest single-module FGD system in the world. The system is designed to achieve 98 percent SO_2 removal burning 3.5 percent sulfur coal and will produce wallboard-quality gypsum. The unit is slated for commercial operation in 2006.

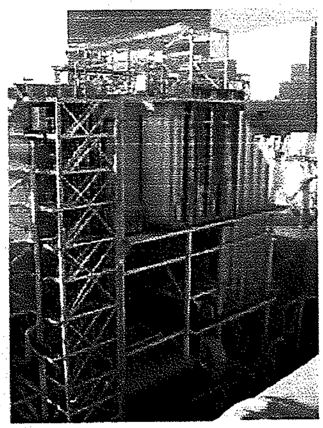
module required. SO_2 removal efficiencies as high as 99.8 percent have been guaranteed and achieved on a 3 percent sulfur fuel while producing wallboard-grade gypsum.

The DCFS FGD system is particularly robust, can tolerate dramatic changes in operating conditions, and is designed to operate two to four years between scheduled outages.

All Advatech's limestone-based FGD systems produce a gypsum byproduct. The majority of these installations sell their gypsum to either wallboard or cement plants.

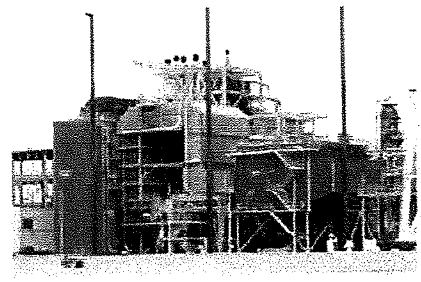
FGD Projects in the U.S.

NiSource Bailly (Pure Air)	530 MWe	95% SO_2 Removal
TVA Paradise	1,060 MWe	98% SO_2 Removal
TVA Widows Creek	500 MWe	96% SO_2 Removal
TVA Colbert	500 MWe	97-98% SO_2 Removal
TVA Bull Run	920 MWe	95-98% SO_2 Removal
Alabama Power Gorgas	1,151 MWe	98% SO_2 Removal



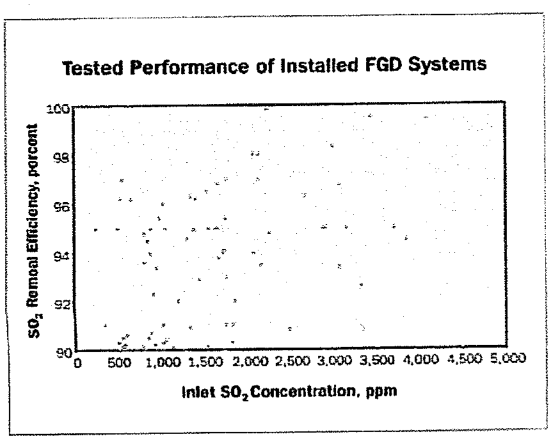
With over two years of continuous operation, this DCFS unit cleans flue gas at Hokkaido Electric's 700 MWe Tomatoazuma station.

Started in early 2002, the 600 MW Kansai Electric Gobo Power Station processes 1 percent sulfur with more than 99 percent SO_2 removal.



The twin tower DCFS FGD system installed at the KOA refinery operates at 99.9 percent SO_2 removal efficiency (without additives), with an inlet SO_2 at 2,100 ppm and less than 2 ppm in the stack. The system produces wallboard-grade gypsum, and has operated at 100 percent availability with four years between scheduled outages since its startup in 1995.

Multipollutant Control Capabilities



In addition to SO_2, the DCFS FGD system is capable of reducing emissions of particulates, acid mist and mercury. The DCFS design which provides the ability to achieve ultra-high (above 99 percent) removal efficiencies of SO_2 without additives is beneficial for the control of other pollutants. Particulate emissions can be reduced by up to 95 percent after locating a high efficiency ESP upstream of the FGD system, and by up to 99.6 percent without a particulate control device. In tandem with a reagent injection process to control acid mist emissions, opacity levels can be reduced to single digits. The DCFS FGD system is also efficient in removing oxidized mercury. In combination with a mercury oxidation

Advatech, through MHI, has extensive experience with FGD systems operating at 100 percent availability on low-and high-sulfur fuels.

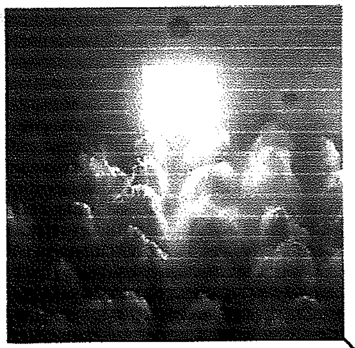
This table shows recent operating experience with DCFS FGD units for a wide range of boiler size, fuel sulfur content and SO_2 removal performance. In total, MHI has more than 160 FGD units worldwide including the world's largest.

Exceptional Performance—No Lost Megawatts

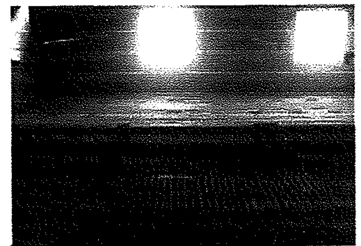
Client		Performance			
Year	**Customer (Location)**	**Capacity (MW)**	**Removal Efficiency (%)**	**Availability (Cumulative) (%)**	**Operating Time Between Outages (years)**
2004	Tokyo Electric Power Company (Hirono, Japan)	600x1	98.3	100	2
2004	Nippon Petroleum Refining Co., Ltd. (Muroran, Japan)	99x1	99.6	100	1
2004	Nippon Petroleum Refining Co., Ltd. (Marifu, Japan)	149x1	99.9	100	1
2003	Kashima Northern Electric Power Co. (Kashima-kita #3,Japan)	300x½	99.4	100	1
2003	COSMO OIL Co., Ltd. (Yokkaichi, Japan)	223x1	99.9	100	1
2003	Sumitomo Joint Thermal Electric Power Co., Ltd. (Nyuugawa, Japan)	250x1	92.8	100	2
2002	Kansai Electric Power Co., Inc. (Gobo #3, Japan)	600x1	99.1	100	2
2002	Hokkaido Electric Power Co., Inc. (Tomatoh-atsuma #4, Japan)	700x1	96.4	100	2
2001	Chugoku Electric Power Co., Inc. (Shimonoseki, Japan)	400×1	97.2	100	2
2000	Nakayama Nagoya Joint Thermal (Nagoya, Japan)	149×1	95.2	100	1
2000	Shikoku Electric Power Co., Ltd. (Tachibanawan, Japan)	700×1	95.0	100	2
2000	Electric Power Development Co., Ltd. (Tachibanawan, Japan)	1,050×1	95.0	100	2
1998	Nippon Petroleum Refining Co., Ltd. (Osaka, Japan)	149×1	99.9	100	1
1998	Chugoku Electric Power Co., Inc. (Misumi, Japan)	1,000×1	90.2	100	2
1997	Sumitomo Osaka Cement Co., Ltd. (Ako, Japan)	100×1	99.3	99.9	1
1997	Fukui Joint Thermal Power Co., Ltd. (Mikuni, Japan)	250×1	96.6	100	2
1992	Kashima South Joint Power Corporation (Kashima, Japan)	146×1	97.1	100	1

catalyst, most of the elemental mercury can be captured as well. More importantly, the efficient forced oxidation systems incorporated in the DCFS design avoids reemitting of oxidized mercury. Advatech is working on providing oxidation catalysts for control of elemental mercury and current pilot plant tests show promising results.

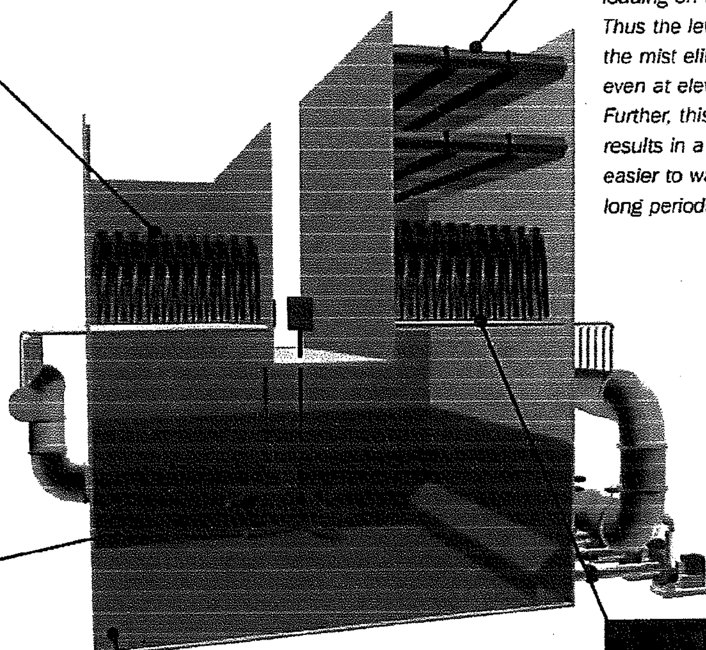
The Advatech DCFS Design

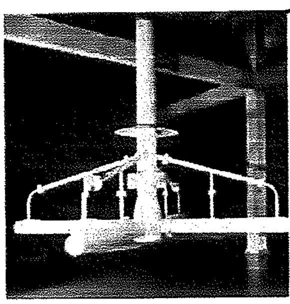


Multiple fountains provide for exceptional gas liquid contact ensuring SO_2 removal efficiencies of up to 99.9 percent! The gas is contacted twice as the liquid sprays upward and as it falls downward. This double contact provides a more efficient mass transfer and higher SO_2 removal per unit of L/G.

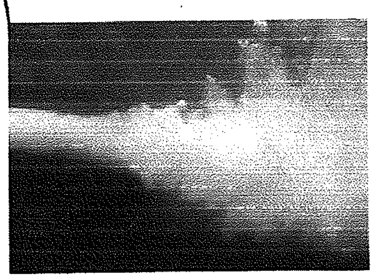


Use of the DCFS fountains for gas liquid contact minimizes the droplet loading on the mist eliminators. Thus the level of liquid loading to the mist eliminators is much less even at elevated gas velocities. Further, this lower liquid loading results in a mist eliminator which is easier to wash and keep clean for long periods between outages.

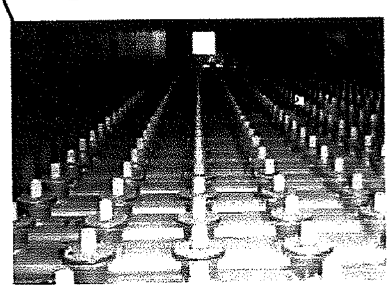




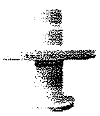
Powerful Air Rotary Sparger (ARS) provides excellent agitation simultaneously distributing fine bubbles used in complete oxidation of calcium sulfite to calcium sulfate. The patented ARS provides an ultra efficient use of oxidation air while ensuring that sufficient gypsum solids exist throughout the module thus minimizing any scaling potential.



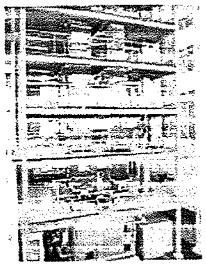
The patented Jet Air Sparger (JAS) was developed to provide oxidation air to the vessel using an eductor to pull atmospheric air (or compressor enhanced air) for oxidation of calcium sulfite to calcium sulfate. The JAS produces very fine air bubbles which enhance the mass transfer and minimize capital and operating costs.



The Advatech DCFS introduces the slurry in a single always-operating spray level. The single level eliminates header-to-header erosion and allows for operation of slurry solids concentration of 30 wt%. The higher solids concentration and the continuous operation ensure the tower stays exceptionally clean and scale free. All recycle pump motors and gear boxes are identical, with a spare recycle pump usually provided to ensure availability.

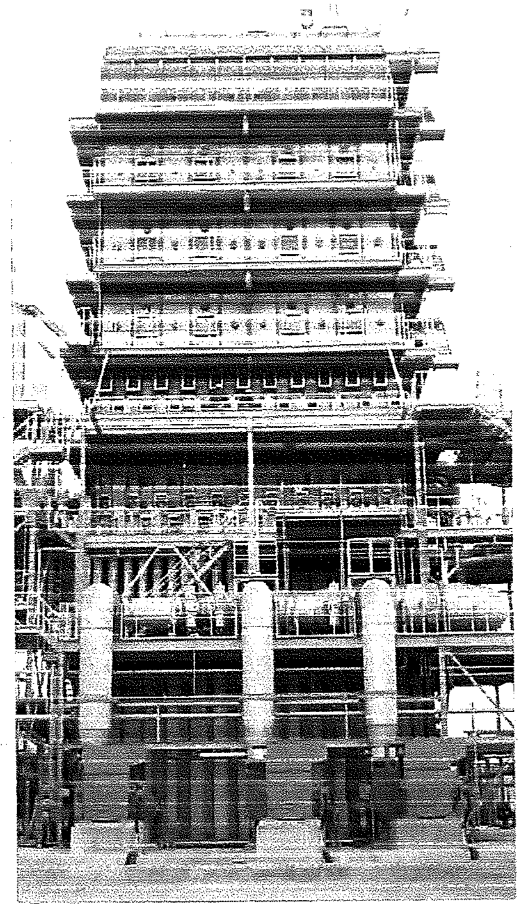


SIC spray nozzle



Pilot plants can use a client's coal, limestone and make-up water to simulate desired conditions.

100 MWe absorber fluid dynamics model



400 MW single-tower DCFS test facility used to improve the single tower design to achieve ultra-high removal capability

Relentless Improvement

Advatech, through MHI and URS, is strongly committed to research and development and to bringing continuous improvements to the utility industry. We have large modern research facilities dedicated to air pollution control.

Advatech's wet FGD system has evolved to a very simple, reliable and highly efficient single loop, double contact flow scrubber. During recent years, prominent technology improvements have included the single stage DCFS spray header design, air rotary sparger for combined slurry mixing and gypsum oxidation, and jet air sparger for gypsum oxidation without use of oxidation compressors.

A full-featured wet FGD pilot plant which can use site-specific coal, limestone and water sources is available to model client-specific operating conditions.

Recent developments have focused on control of trace emissions such as sulfuric acid mist (SO_3) and mercury (Hg). URS has introduced a new process for control of SO_3 emissions by use of sodium by-sulfite injection. When injected upstream of the air preheater, the acid dew point is lowered sufficiently, which can result in a significant increase in boiler efficiency. Mercury control technologies are being studied vigorously by both URS and MHI, and technologies for control of mercury emissions will be introduced to the market in the near future.

Advatech brings the full talent and capabilities of MHI and URS research and development to the market. We design our control technologies to account for future emissions control requirements. Our technologies will help you bridge the gap to future emissions control legislation.

Corporate Strength

Advatech combines the strength of two world-class organizations—URS and Mitsubishi Heavy Industries America—to bring the best FGD systems to the United States. With Advatech, you get not only the DCFS technology, but also all the R&D, engineering and implementation experience, and the corporate commitment from both companies. Advatech is providing design and construction services to the Tennessee Valley Authority for up to five FGD systems. Advatech is now designing the first large FGD system for the Southern Company—at Alabama Power's Plant Gorgas.

The Next Generation

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Bachman, Tom A.

From: Platt.Amy@epamail.epa.gov
Sent: Monday, February 08, 2010 9:51 AM
To: Bachman, Tom A.; Morales.Monica@epamail.epa.gov
Cc: Golden.Kevin@epamail.epa.gov
Subject: Re: Heskett Unit 2

Tom:

Based on our review of AECOM's December 17, 2009 "Updated BART Modeling Results for R.M. Heskett Station Unit 2," our preliminary conclusions are that an EPA-approved protocol was used, and the results indicate that Heskett Unit 2's impact was less than the subject-to-BART threshold of 0.5 deciviews. Therefore, it appears appropriate for the State to determine that the source is not subject to BART. However, the source may still qualify for potential emission reductions under the Reasonable Progress requirements of the Regional Haze Rule. In addition, please note that we can only reach a final decision regarding the modeling and its results, and any other aspect of the Regional Haze SIP, through our own notice and comment rulemaking.

Thanks for your follow-up on this one......Amy

Amy Platt, Environmental Scientist, 8P-AR
EPA Region 8, Air Program
1595 Wynkoop Street
Denver, CO 80202

303-312-6449 (voice), 303-312-6064 (fax)
Platt.Amy@epa.gov

-----"Bachman, Tom A." <tbachman@nd.gov> wrote: -----

To: Amy Platt/R8/USEPA/US@EPA
From: "Bachman, Tom A." <tbachman@nd.gov>
Date: 02/01/2010 10:23AM
Subject: Heskett Unit 2

Amy:

Will we be getting a letter from you indicating that EPA concurs that Heskett Unit 2 is not subject to BART? We would like to have it for our records.

Tom Bachman
Sr. Env. Engr.
ND Dept. of Health
(701) 328-5188

General Comments

Comment 1: The Department received 30 nearly identical emails from various individuals. The emails asked the Department to require additional control on the power plants and more aggressively pursue identified emissions reductions from all sources of pollutants. This was also reiterated in two additional emails and the oral testimony by Jim Kambeitz.

Response: The Department has required all emissions reductions that are required by rule or law. The SIP will reduce SO_2 emissions from power plants by approximately 68% and nitrogen oxides emissions by approximately 39% (based on 2000-2004 average emission rate). Overall, sources in North Dakota will reduce total sulfur dioxide emissions by approximately 106,000 tons/yr (60%) and nitrogen oxides by 58,000 tons/yr (25%). The uniform rate of progress for this planning period would only require a 23.3% improvement in visibility. The Department believes the reductions that will be achieved represent North Dakota's fair share of emissions reductions for the planning period. None of the commenters provided any technical argument that the Department was not complying with the Clean Air Act or the rules promulgated thereunder. The Department stands by its decision.

Comment 2: Two email commenters suggested that the Department needed to require additional emissions reductions in order to protect public health.

Response: The Department has reviewed ambient monitoring data in the Beulah area which is the most heavily affected area by power plants and a coal gasification plant. Five ambient monitors are operated in the immediate area. In 2008, the maximum 3-hr SO_2 concentration was 39 ppb (7.8% of the NAAQS), the maximum 24-hour SO_2 concentration was 9 ppb (6.4% of the NAAQS), and the maximum annual average SO_2 concentration was 1.8 ppb (6% of the NAAQS). For NO_2, the maximum annual average concentration was 2.7 ppb (5.1% of the NAAQS). The NAAQS were established by EPA to protect public health and welfare, including young individuals, with an adequate margin of safety. The reduction in emissions from the power plants and the other sources should reduce these ambient concentrations. The Department believes the public health and welfare is protected and air quality only will improve with the proposed reductions in emissions.

Montana Dakota Utilities Comments

Comment 1: Montana Dakota Utilities (MDU): MDU recalculated the expected SO_2 reductions at Heskett Station Unit 2 from limestone injection into the boiler. They excluded 2002 from the calculation and calculated a 474 tons per year reduction.

Response: The Department has reevaluated its calculation of the expected reduction. To be consistent with calculations for other sources, 2002 data was not eliminated. Based on the reevaluation, the Department expects a 553 ton/yr reduction from the 2000-2004 average emission rate.

Comment 2: MDU wanted the latest BART applicability modeling analysis and EPA's approval of the modeling protocol included in the final SIP revision.

Response: These documents will be included in the final SIP revision.

Comment 3: MDU asked the Department to consider the amount of visibility improvement that could be achieved by adding controls to Heskett Unit 2 when determining the reasonable progress goals.

Response: The visibility improvement will be considered in the calculation of cost (i.e., dollar per deciview). The other three factors for determining reasonable progress will also be considered.

Department of Interior (DOI) Comments

The DOI comments took the form of a response to the Department's response to the DOI comments of October 23, 2009.

Comment 1: The DOI still contends that TRNP should be treated as one area for visibility modeling.

Response: The Department still believes that the three units of TRNP should be treated as three distinct areas. Our reasons are stated in our response to the October 23, 2009 comments. We stand by our comments.

Comment 2: Regenerative Selective Catalytic Reduction (RSCR) should be evaluated.

Response: As pointed out by the commenter, this type of system requires much more space than a conventional TESCR system. Both the M.R. Young Station and Leland Olds Station have limited space and could not accommodate RSCR. The commenter indicated that RSCR has a high capital cost when compared to conventional SCR. The Department rejected TESCR and LDSCR at all four stations due to an excessive cost and/or lack of significant improvement in visibility. This unit will not provide any improvement in visibility over conventional TESCR and LDSCR. No technical details were provided so that the Department could make a comparison; therefore, it is not considered BART.

Comment 3: Follow up to October 23, 2009 comment 6.

DOI suggested that the Department should explain how it considered the benefits of reducing emissions with respect to visibility improvements at multiple Class I areas.

Response: The Department provided visibility modeling results for LWA and the three units of TRNP. We looked at both the maximum improvement at each of the four areas; the average for each area and the average for all of the areas (see tables in each BART analysis). We believe we have complied with the Clean Air Act.

As pointed out previously, only the Coal Creek Station is subject to the BART Guideline (40 CFR 51, Appendix Y) and only for NO_x. EPA has stated that "… states are not required to follow these guidelines for EGUs located at power plants with a generating capacity of less than 750 MW" (FR Vol. 70, No. 128, 39131). Within the Guideline, EPA states "For sources other than 750 MW power plants, however, States retain the discretion to adopt approaches that differ from the guidelines" (Appendix Y to Part 61, Section I.H.). The NDDH has exercised this discretion when evaluating the various BART options.

<u>Comment 4</u>: Follow up to Comment 8 from October 23, 2009

DOI stated that they had commented to EPA Region 9 that they had underestimated the efficiency of SCR in the ANPR for the Four Corners Plant.

<u>Response</u>: The Department has reviewed the EPA Air Pollution Control Cost Manual which states "In practice, SCR systems operate at efficiencies in the range of 70% to 90%". EPA's Air Pollution Control Technology Fact sheet for selective catalytic reduction (EPA-452F-03-032) states "SCR is capable of NO_x reduction efficiencies in the range of 70% to 90%". The Oregon DEQ hired Eastern Research Group, Inc. (ERG) to review the BART analysis for the PGE Boardman Plant. In their review, ERG stated "With regard to the performance of existing low NO_x burners (LNB) with overfire air (OFA) and SCR, reductions of 70 to more than 90 percent have been documented from recent installations; however, these are based on units that operate mainly during the ozone season and that have substantial opportunity for off-season maintenance and catalyst cleaning. The impact of existing LNB with OFA and SCR of the Boardman Plant under year-round operation would need to be considered in selecting a permit level." The NDDH believes the use of 80% is a reasonable choice for a source that must meet a BART emission limit on a long-term continuous basis.

<u>Comment 5</u>: Follow up to Comment 9 from October 23, 2009

DOI indicated they had commented to EPA Region 9 that the cost of SCR had been overestimated.

<u>Response</u>: In addition to the EPA estimate for SCR at the Four Corners Power Plant, the Department also reviewed the analysis commissioned by the Oregon DEQ for the cost of SCR at the PGE Boardman Plant. The analysis, which was prepared by Eastern Research Group, Inc. (ERG) states, "Nonetheless, all of these sources do point to a rapid escalation in SCR installed costs since 2004. ERG analyzed the 2007 cost-basis data by eliminating the three highest and one project that was known to be very dissimilar to the Boardman Plant characteristics. The remaining nine projects range from \$207/kw to \$267/kw, with an average of \$227/kw. ERG believes that this is a reasonable representation of 2007 costs of large SCR installations under normal retrofit conditions." DOI's estimate of the Total Direct Capital costs for SCR was less than \$150/kw for all facilities and substantially less for most units (i.e. \$101/kw at Stanton Unit 1). The NDDH <u>continues</u> to believe DOI has severely underestimated the cost of SCR. Since high dust SCR is not technically feasible for North Dakota lignite; the DOI cost estimates are even more erroneous since they do not include a reheat system or reheat annual costs. Based on the above, we believed the EPA Control Cost Manual is inappropriate for estimating the cost of

SCR. The manual states in Section 2.4 that the costs for tail-end SCR cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements.

Comment 6: Follow up to comment 10 on October 23, 2009

DOI believes the NDDH is placing too much emphasis upon incremental differences in visibility improvement. NDDH should support their claim that single source modeling overpredicts the actual improvement by a factor of 5-7.

Response: The preamble to the BART Guideline states "Because each Class I area is unique, we believe states should have flexibility to assess visibility improvements due to BART controls by one or more methods, and we agree with commenter's suggestions to do so." (FR Vol. 70, No. 128, p.39129). The NDDH has looked at the difference in improvement for each control option. This is the same as looking at the total improvement for each control option and determining the difference in visibility improvement. Indirectly, the total improvement of each option is considered.

The difference between cumulative and BART single-source modeling results starts with the logarithmic relationship between deciview and light extinction, which is based on the proven concept that an observer will detect visibility changes more easily in clean air than in dirty air. Deciview is related to light extinction using the equation

$$dv = 10 \times \ln(b_{ext} / 10)$$

where

dv = deciview

b_{ext} = light extinction in units of inverse mega-meters (Mm^{-1})

In BART single-source modeling, the incremental impact of the subject source is based on a background of natural visibility conditions only. In cumulative modeling, as conducted by WRAP, the incremental impact of the subject source is based on a background of natural visibility conditions plus the impact of a complete inventory of all other source emissions which affect visibility. Therefore, calculated delta-deciview for the subject source for the cumulative case will be lower than for the single-source case.

A simple hypothetical example can illustrate the difference in single-source and cumulative visibility modeling. Assume that a subject source is contributing 5 Mm^{-1} to total light extinction and that the natural visibility background is 20 Mm^{-1}. Under single-source modeling, delta-deciview for the subject source would be calculated:

$$\text{delta-dv} = [10 \times \ln(25 / 10)] - [10 \times \ln(20 / 10)] = 9.16 - 6.93 = 2.23$$

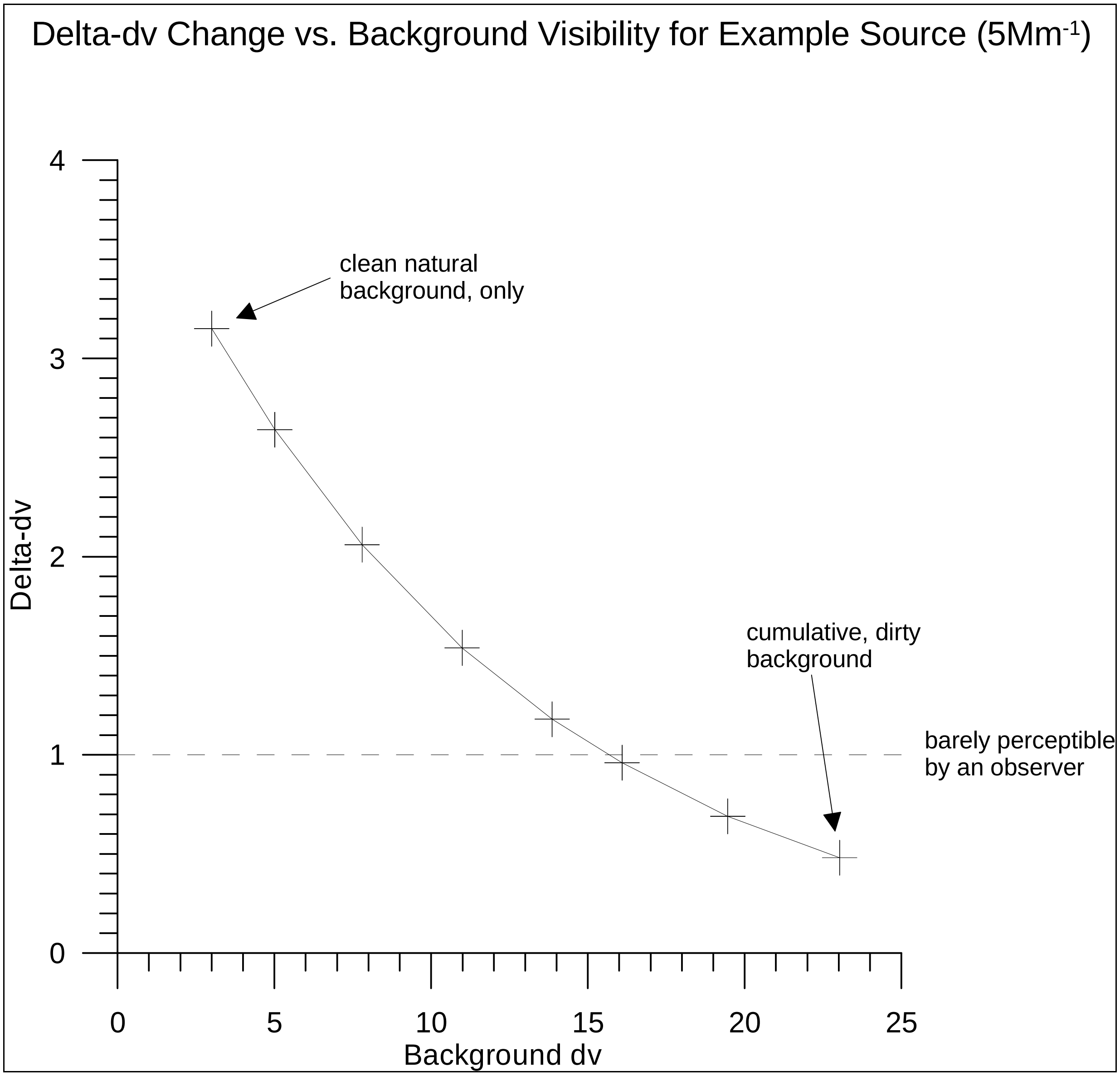
WRAP and the NDDH have found that adding a complete emissions inventory in the cumulative modeling will typically result in a background more than double the natural visibility conditions.

So to complete the example for the cumulative modeling case, we assume a background of 50 Mm^{-1} and the same subject source. Delta-deciview for the subject source would be calculated:

delta-dv = [10 x ln(55 / 10)] – [10 x ln(50 / 10)] = 17.05 – 16.09 = 0.96

Therefore, inclusion of the complete visibility-affecting emissions inventory in the cumulative modeling produces a smaller, but more realistic, observer-detected difference of 0.96 deciview from the subject source. In fact, for this example, the cumulative modeling result falls below the generally recognized observer-detectable threshold of about 1.0 deciview. Thus, the example illustrates that the impact of the subject source plume against a clean background would be much more noticeable to an observer than the impact of the same plume against the more realistic dirtier background. And, obviously, any change in visibility-affecting emissions from the subject source would have a smaller impact on the observer under the cumulative modeling scenario.

In the figure below, delta-deciview has been plotted for several background deciview levels, based on the subject source above. The included background levels range from a clean natural background to a dirty background representing the cumulative effect of many visibility-affecting sources. The plot includes the two points calculated above. The plot illustrates the general dependency of the observed visibility change (delta-deciview) on the background level, and the fact that an observer's perception of visibility change can vary greatly depending on the background deciview level. In fact, for this example, there is a factor of 6.6 difference in delta-deciview for the cleanest background compared with the dirtiest background (3.15 / 0.48 = 6.56).



To further illustrate the difference in single-source and cumulative visibility analyses, the NDDH conducted additional modeling using actual sources. For this illustration, the NDDH grouped the BART-applicable Coal Creek, Leland Olds, and Milton R Young Generating Stations (in North Dakota) as an effective single source. Single-source and cumulative modeling analyses were conducted to determine the incremental visibility improvement at Theodore Roosevelt National Park from the 3-source group, based on BART controls. Calpuff system versions 5.8, the new IMPROVE equation, annual average natural background, and consistent annual emission rates (for the three noted sources) were applied for both analyses. The 90th percentile visibility day from the single-source modeling results was used to emulate the 20% worst day average from the cumulative modeling results. (Given that the typical distribution of 20% worst day visibilities tends to be skewed toward the high end, the 90th percentile day may somewhat understate the

20% worst day average). Note that the post-BART emissions inventory for the cumulative analysis included changes only to the three sources referenced above.

Results of the NDDH modeling analyses are summarized in the table below. The modeling analyses discussed above are compared in the first two columns of results.

	20% Worst Day Avg. Cumulative Modeling	90th Percentile Day Single-Source Modeling	90th Percentile Day Single-Source Modeling Using 2005 ND BART Protocol
Baseline (dv)	16.954	6.552	5.583
Post-BART (dv)	16.493	5.641	3.288
Improvement (delta-dv)	0.461	0.911	2.295

As shown in the table, visibility improvement from the addition of BART controls to the three generating stations based on single-source modeling is about twice that found from cumulative modeling. These results are consistent with the hypothetical example discussed above.

Also shown in the table are results of a third modeling scenario, i.e., single-source modeling based on the North Dakota BART modeling protocol. Consistent with EPA recommendations at the time (2005), the North Dakota BART protocol specified the use of Calpuff Version 5.7, the old IMPROVE equation, and a natural background reflecting cleanest days. In addition, the protocol specified use of maximum 24-hour emission rates, per the BART Rule. As indicated in the table, use of this protocol resulted in a much greater “apparent” improvement in visibility, about a five-fold increase in the result from the cumulative modeling. This illustration, therefore, is another basis for the NDDH statement in the SIP that BART single-source modeling over predicts by a factor of 5 to 7.

All BART modeling conducted by the NDDH and industry was based on the North Dakota BART protocol. Given differences in the North Dakota BART protocol (compared to later protocols), combined with the logarithmic nature of the relationship between deciview and light extinction, it becomes clear that BART single-source modeling could have greatly overstated the more realistic results obtained from recent cumulative modeling for North Dakota.

Note that use of the ND BART single source modeling produces a visibility improvement at Theodore Roosevelt National Park (2.295 dv) which achieves compliance with the uniform rate of progress goal (2.3 dv as discussed in Section 5 of the North Dakota SIP). If one was to accept the premise that these single-source modeling results are realistic, it would logically follow that North Dakota has met the uniform rate of progress based on BART controls for the three modeled sources, and that the need to address additional (non-BART) visibility-affecting emissions reductions in North Dakota is therefore less compelling.

The 20% worst-day average metric from cumulative modeling and the 90th percentile day metric from single-source modeling have been compared in this illustration as they constitute a comparable moment of the annual distribution of daily visibility predictions. Obviously, the 98th percentile day metric from single-source modeling would provide an even greater exaggeration of actual visibility change than the 90th percentile, in the context of the 20% worst-day average metric required to measure progress with respect to visibility goals under the regional haze rule.

<u>Comment 7</u>: Follow up comment 10C from October 23, 2009

DOI still believes that modeling should be based on the future conditions instead of the year that match the meteorology.

<u>Response</u>: As pointed out previously, the BART Guideline states that the emission rates for determining visibility for the precontrol scenario, the highest emission rates from the meteorological period modeled should be used. When determining visibility improvement, the comparison is made from a baseline, not a future scenario. This affords consistency from state-to-state and allows emissions data to be paired with meteorological data to produce the best prediction of baseline visibility conditions.

<u>Comment 8</u>: Follow up to comment 11 from October 23, 2009

DOI still believes NO_x reductions improve visibility more than SO_2 reductions.

<u>Response</u>: The Department agrees that NO_x reductions may be more effective than SO_2 reductions in reducing some visibility-affecting species' concentrations under some conditions, especially at a generally cooler, northern location versus a warmer, southern location. This is especially true because of the strong temperature dependence of the chemical reaction that forms NO_3 from HNO_3. The following table illustrates the strong temperature and relative humidity dependence of the reaction that forms ammonium nitrate from HNO_3 and the extreme values that can occur given typical values for [NH_3] and [HNO_3] of 1 ppb each. The equilibrium constant of the reaction is K and has an inverse relationship with [NH_4NO_3].

T(deg.C)	T(deg.F)	RH(%)	K(ppb)	[NH_4NO_3](ppb)
40	104	50	1000	0.001
30	86	40	100	0.01
30	86	90	20	0.05
20	68	40	8	0.13
20	68	90	2	0.5
10	50	40	0.6	1.7
10	50	90	0.2	5
0	32	40	0.03	33
0	32	90	0.01	100
<0	<32	<80	<0.01	>100

It is recognized that lower temperatures favor production of ammonium nitrate, for example, over production of HNO_3 from NO_x emissions. Conversely, warmer temperatures favor production of HNO_3 over NO_3, including during warmer months in North Dakota. During winter months in North Dakota, lower temperatures produce more potential for higher NO_3 concentrations than in the summer, when potential NO_3 concentrations are relatively low because of warmer temperatures. This temperature effect can be seen in the time-series plots of nitrate concentrations over an annual cycle, displayed in Figure 8.11 of the SIP document. Note the relatively low NO_3 concentrations during the summer and adjacent warmer periods and the higher NO_3 concentrations during the rest of the year.

Nevertheless, potentially higher NO_3 concentrations are only favored in the winter and colder days in spring and fall in North Dakota, and only then when NH_3 and NO_x emissions are high enough, and when winds transport NO_x plumes toward Class I areas and dispersion of plumes is not favorable. During the summer and about half of the spring and fall in North Dakota, ambient temperatures are warmer, similar to the rest of the U.S., and thus high NO_3 concentrations would not be favored then.

It may be true that it is easier to obtain lower NO_3 concentrations from NO_x reductions in a generally cooler, northern location than at a warmer, southern location, because of the temperature dependence in the chemistry. Nevertheless, obtaining visibility improvement by lowering SO_4 concentrations through SO_2 reductions is a reliable, effective way of improving visibility in North Dakota, somewhat because of the less complex chemistry involving SO_2. Reducing SO_2 emissions to improve visibility has the advantage of being effective year round, whereas NO_x reductions would be less effective during warmer months because of the lower potential NO_3 production from the temperature dependence in the chemistry.

Comment 9: Follow up to comment 12 from October 23, 2009

DOI still believes the dollar per deciview improvement is still the metric to emphasize when determining BART.

Response: As far as the emphasis on incremental differences between controls options, see response to comment 6.

DOI apparently did not understand the NDDH response when it pointed out that accuracy of single source modeling when compared to cumulative modeling can vary from state-to-state. As such, the accuracy of a dollar per deciview calculation will vary from state-to-state. This is due to a variation in the number of sources that affect the Class I area, the amount of emissions that affect the area and the location of the sources that affect the area. This makes this metric of very little value.

Comment 10: Follow up to comment 13 from October 23, 2009

DOI believes the proposed SO_2 control technology could meet the lower lb/MMBtu limit (assumed 0.15 lb/10^6 Btu) even if coal quality deteriorates.

Response: The Department did not use the maximum sulfur content in determining the BART limits. The Department used an annual average sulfur content. In the case of Minnkota's M.R. Young Station, the maximum sulfur content is 5.6% with an average of 0.93%. In order to comply with a 0.15 lb/10^6 Btu standard when burning the maximum sulfur coal, the scrubber would have to achieve 98.9% efficiency. This is extremely difficult with a wet scrubber.

Comment 11: Follow up to comment 25 from October 23, 2009

The DOI continues to assert that the WYGEN3 permit should be used as a basis for requiring Stanton Unit 1 to meet a 93% control for SO_2 and an emission limit of 0.09 lb/MM Btu on a 30-day rolling average basis.

Response: The DOI continues to ignore the fact that the WYGEN3 permit does not establish any minimum SO_2 control efficiency, let alone a 93% control efficiency. The WYGEN3 permit only establishes SO_2 emission limits on a lb/hr, lb/MW-hr and lb/MM Btu basis. As stated in the Department's initial response, the WYGEN3 facility could burn low-sulfur coal and still comply with the emission limits with SO_2 control efficiencies below 90%.   As also indicated in the Department's initial response, it is the Department's understanding that the WYGEN3 facility has yet to demonstrate that the SO_2 emission limits can be achieved.

The Department maintains the position that a SD/FF operating at Stanton Station Unit 1 is capable of achieving an average SO_2 control efficiency of 90%.

Comment 12: Follow up to comment 26 from October 23, 2009

The DOI states that the "NDDH should show how it arrived at the conclusion that 'based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton Unit 10 is estimated to be approximately 90%.'"

Response: The Department estimated the control efficiency based upon data contained in the annual emission inventory report for the Stanton Unit 10 facility. Uncontrolled emissions were calculated based upon AP-42 emission factors. Actual (controlled) emissions are measured by the CEM at Stanton Unit 10. This data is public information which will be provided to the DOI upon request.

Comment 13: Follow up to comment 29 from October 23, 2009

The DOI asserts that it may be possible that SOFA with SCR with reheat may be less expensive than just SCR with reheat since the additional capital cost of adding SOFA may be offset by reduced annual operating costs.

Response: The DOI provides no data to support this position. The BART analysis for the M.R. Young facility estimates the annualized cost for SCR with reheat with ASOFA to be approximately $99,600 to $143,570 per MWe. The estimated annualized cost for SCR with reheat at Stanton Unit 1 is approximately $66,435 per MWe. Based upon this data, the cost of adding ASOFA is expected to significantly increase the annualized cost. Although adding SOFA may be somewhat less expensive than adding ASOFA, in the Department's judgment it is very likely that the cost of SOFA with SCR with reheat will be higher than the cost of SCR with reheat alone.

In the specific case of the BART analysis for Stanton Unit 1 the incremental cost of applying SCR with reheat is $10,032 per ton of NO_x controlled when burning lignite and $12,894 per ton of NO_x controlled when burning PRB. It would be necessary for the addition of SOFA to reduce the incremental costs considerably for the application of SOFA with SCR with reheat to not be considered cost prohibitive. As indicated above, it is very likely that the addition of SOFA would increase costs significantly and not decrease costs significantly. Therefore, in the Department's judgment an analysis of SOFA with SCR with reheat would not alter the conclusion that SOFA with SCR with reheat is cost prohibitive at Stanton Unit 1.

Comment 14: Follow up to comment 30 from October 23, 2009

The DOI continues to question the cost estimates for SCR with reheat included in the BART analysis.

Response: In previous comments submitted by DOI, the DOI questioned GRE's estimate of the capital cost of SCR with reheat of $301/kW based upon the fact that the cost exceeded what the DOI deemed to be an acceptable range of $50-$267/kW. The DOI bases the acceptable range on a cost survey and one of the documents referenced by DOI includes a June 26, 2008 technical memorandum prepared by Eastern Research Group, Inc. (ERG) regarding the PGE Boardman Plant. In this document, ERG references an acceptable cost range for SCR (apparently without reheat or gas-to-gas heat exchanges – GGHE) of $207-$267/kW. However, the ERG memorandum also references a cost estimate prepared by Black & Veatch and CH2M Hill for the PGE Boardman Plant of $309/kW (apparently for SCR without reheat). The Black and Veatch / CH2M Hill cost estimate was not referenced by the DOI. Based on the GRE BART submittal, the capital cost estimate for addition of the thermal oxidizer necessary to reheat the flue gas is approximately $1.275 million (approximately $7 per kW). Adding this to the above-referenced ERG cost ranges results in a range of approximately $214-$274/kW. Adding the $7 per kW cost to the Black and Veatch / CH2M Hill cost estimate results in a cost estimate of approximately $316/kW.

Based on the above, it can be seen that the GRE capital cost estimate for SCR with reheat of $310/kW is approximately 10% higher than the highest cost value of $274/kW prepared by ERG (adjusted for SCR with reheat but without the GGHE). The GRE capitol cost estimate for SCR with reheat is approximately 2% lower than the cost estimate of $316/kW prepared by Black and Veatch / CH2M Hill for the PGE Boardman Plant (adjusted for SCR with reheat but without the GGHE). Based upon this data, the GRE cost estimates appear to be in the range of similar cost estimates. This is especially true considering the inherent difficulty in calculating actual costs. Both the New Source Review Workshop Manual and the EPA Air Pollution Control Cost Manual state that control cost estimates are typically accurate within ± 20 to 30 percent. Based upon the above, the GRE cost estimate for SCR with reheat appears to be reasonable.

The DOI also continues to question how the Department verified the cost estimates. An example of how the Department verifies cost estimates is shown above. As can be seen from the above, the Department verified the cost estimates by comparing the calculated costs with all relevant data. The Department also verifies the actual calculations to determine if the values used are reasonable. Based on the ongoing comments, it appears that the DOI has relied on outdated models to estimate costs. As the Department has demonstrated in previous responses to DOI comments, the DOI cost estimates for other projects have been found to be significantly lower than EPA cost estimates for the same projects.

Comment 15: Follow up to comment 34 from October 23, 2009

DOI is suggesting a higher efficiency for SCR.

Response: See response to comment 4.

Comment 16: Follow up to comment 35 from October 23, 2009

DOI claims that the NDDH cannot simply halt the BART process by determining that a technically feasible option is too expensive on a cost per ton basis.

Response: The preamble to the BART guideline states "The interpretation of the requirements of the regional haze program reflected in the discussion above does not necessitate costly and time-consuming analyses. Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach [emphasis added] to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible." (F.R. Vol. 70, No. 128, p.39116). The cost of SCR is obviously excessive. Based on the visibility modeling results from Unit 2, the amount of improvement is visibility in any Class I area will be less than 0.01 deciviews in the most impaired days or approximately 0.10 deciviews (overall average) based on the 98th percentile value from the single source modeling when compared to the next best control technology. This amount of visibility improvement is negligible.

The Department is free to weigh the five factors as we choose (FR Vo. 70, No. 120, p.39130). As we have indicated, visibility improvement has been given little weight in the BART process. In the case of a control technology that is obviously excessive in cost on a dollar per ton basis, visibility improvement was given even less weight. That is, a control option that has an excessive cost on a dollar per ton basis, there is no reason to model the visibility improvement because visibility improvement will be a small part of the decision making process. There are literally dozens of control options with varying degrees of removal efficiency that could be analyzed. To make a workable BART process, not all options can be modeled to determine the amount of visibility improvement.

Comment 17: Follow up to comment 37 from October 23, 2009

DOI believes visibility modeling must be done for SOFA + SCR and SCR.

Response: See response to comment 16.

Comment 18: Follow up to comment 49 from October 23, 2009

DOI is advocating a startup limit (lb/hr) based on the BART allowable and the maximum rated heat input of the unit.

Response: For wall and tangentially fired boilers, the DOI suggestion may work. Because cyclone boilers emit at such a high rate during startup (>1.0 lb/10^6 Btu), limiting the emissions based on DOI suggestion does not provide the relief necessary. The unit would exceed the lb/hr limitation when the heat input is only 1/3 of the rated capacity or less. This would lead to extended periods of noncompliance. The NDDH believes the proposed limit is necessary for Minnkota since they did not include startups in the proposed BART limit. The Consent Decree for Minnkota requires these limits to be established separately.

Comment 19: Follow up to comment 54 from October 23, 2009

Same comment as comment 23 except for M.R. Young Unit 2.

Response: See response to comment 18.

Comment 20: Follow up to comment 63 from October 23, 2009

DOI indicated that NDDH should seriously evaluate all significant sources of human-caused impairment. They also questioned whether cumulative visibility improvement cited in the SIP included controls on Coyote and AVS.

Response: The NDDH considered all the significant sources of visibility impairing pollutants including any source that emits more than 100 tons per of sulfur dioxide and nitrogen oxides combined, oil and gas production facilities, prescribed burning, agricultural tillage operations and mobile sources. The NDDH believes this represents nearly all of the SO_2 and NO_x emissions from anthropogenic sources. The analysis that was conducted indicates it is not reasonable to control these sources.

The cumulative visibility modeling shown in the SIP did include controls for Coyote and AVS. For Coyote Station, this included a new wet scrubber plus ASOFA + SNCR. For AVS, this included LNB + SNCR.

Attachments

1. Email and other general comments
2. Montana Dakota Utilities complete comments
3. Department of Interior complete comments

Bachman, Tom A.

From: odinwan@cableone.net
Sent: Wednesday, December 16, 2009 6:42 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

My grandfather homesteaded in the badlands, and my dad grew up there. My sister and I spent most weekends there, and I have a deep appreciation for the beauty, and also the pollution free air there. Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

The Clean Air Act requires old power plants and factories to reduce haze-causing pollutants. Technology exists to reduce this pollution--technology that will protect our national parks and wilderness areas, and public health. It is important that the Act and other air quality regulations are followed, so that we can enjoy these parks now and preserve them for our children and grandchildren.

The State of North Dakota can and should do more to protect our air quality as it implements the Regional Haze Rule. I request that the haze plan impose stricter limits on pollution from power plants and other industrial sources. In particular, North Dakota should require all appropriate coal plants to install more effective pollution control devices, and more aggressively pursue identified emission reductions from all sources.

Without this and other measures, North Dakota's coal plants will continue to unnecessarily obscure views in our national parks and wilderness areas for decades to come and deter tourists, including me and my family, from visiting the state of North Dakota and the beloved parks in the region. North Dakota must do its part to ensure that the air in our parks, and throughout the region, will indeed be restored to natural conditions.

Thank you for considering my comments.

Sincerely,
Alice Christianson
2807 25 Av S
Fargo, ND 58103

Bachman, Tom A.

From: larrett@gwtc.net
Sent: Wednesday, December 16, 2009 5:52 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Penny Larrett
13019 Lakeview Dr.
Hot Springs, SD 57747

Bachman, Tom A.

From: ron@cattletech.com
Sent: Wednesday, December 16, 2009 4:58 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
ron ragsdale
613 Main St
Rapid City, SD 57701

From: jannrayg@gwtc.net
Sent: Wednesday, December 16, 2009 5:35 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Ray Gellerman
12349 Moss Rock Lane
Custer, SD 57730

Bachman, Tom A.

From: a.goering@sio.midco.net
Sent: Wednesday, December 16, 2009 4:05 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Arden Goering
3305 E 33rd Street
Sioux Falls, SD 57103

Bachman, Tom A.

From: gbloomer@gwtc.net
Sent: Wednesday, December 16, 2009 3:47 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Jerry Bloomer
2146 Minnekahta Avenue
Hot Springs, SD 57747

Bachman, Tom A.

From: tinker1447@aol.com
Sent: Wednesday, December 16, 2009 3:36 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Linda Meilink
2040 W Main St
Ste 210- #1656
Rapid City, SD 57702

Bachman, Tom A.

From: jahag74@yahoo.com
Sent: Wednesday, December 16, 2009 3:27 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Jamie Hagen
37989 138th Street
Aberdeen, SD 57401

Bachman, Tom A.

From: agayken75@yahoo.com
Sent: Wednesday, December 16, 2009 3:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Aaron Gayken
310 W. 21st St. #9
Sioux Falls, SD 57105

Bachman, Tom A.

From: tall_n_silvery@yahoo.com
Sent: Wednesday, December 16, 2009 3:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

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Thank you for considering my comments.

Sincerely,
Linda Jagielo
166 Boise Ave
Bismarck, ND 58504

Bachman, Tom A.

From: sheridar@gmail.com
Sent: Wednesday, December 16, 2009 3:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Sherida Ribordy
1806 Rushmore St.
Rapid City, SD 57702

Bachman, Tom A.

From: harming@rushmore.com
Sent: Wednesday, December 16, 2009 3:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

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North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
W. Harming
P.O. 9402
Rapid City, SD 57709-9402

Bachman, Tom A.

From: scotthed@hotmail.com
Sent: Thursday, December 17, 2009 8:03 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a resident of South Dakota as well as a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

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Thank you for considering my comments.

Sincerely,
Scott Hed
713 S. Holt Avenue
Sioux Falls, SD 57103

Bachman, Tom A.

From: jewels17_17@hotmail.com
Sent: Thursday, December 17, 2009 7:38 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Director O'Clair,

Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

The Clean Air Act requires old power plants and factories to reduce haze-causing pollutants. Technology exists to reduce this pollution--technology that will protect our national parks and wilderness areas, and public health. It is important that the Act and other air quality regulations are followed, so that we can enjoy these parks now and preserve them for our children and grandchildren.

The State of North Dakota can and should do more to protect our air quality as it implements the Regional Haze Rule. I request that the haze plan impose stricter limits on pollution from power plants and other industrial sources. In particular, North Dakota should require all appropriate coal plants to install more effective pollution control devices, and more aggressively pursue identified emission reductions from all sources.

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Thank you for considering my comments.

Sincerely,
Julie Landkamer
208 N 3rd Street
Drayton, ND 58225

Bachman, Tom A.

From: pcw577@hotmail.com
Sent: Thursday, December 17, 2009 6:49 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Charles Wirth
605 Judson Ave
Hurley, SD 57036

Bachman, Tom A.

From: gjturner@westriv.com
Sent: Thursday, December 17, 2009 2:31 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Julie Turner
28759 127th St.
Mobridge, SD 57601-5000

Bachman, Tom A.

From: bessythree@yahoo.com
Sent: Thursday, December 17, 2009 1:42 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Ron Ratner
3700 S Westport Ave #3769
Sioux Falls, SD 57106

Bachman, Tom A.

From: hawkins_j_m@hotmail.com
Sent: Wednesday, December 16, 2009 10:30 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Ran Zirasri
423 W. Century Ave. Apt. 201
Bismarck, ND 58501

Bachman, Tom A.

From: mantyfan@yahoo.com
Sent: Wednesday, December 16, 2009 8:56 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Pamela Kjono
1146 McKinley Avenue
Grand Forks, ND 58201

Bachman, Tom A.

From: ndhockeyfan87@yahoo.com
Sent: Wednesday, December 16, 2009 7:19 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Elaine Matthew
216 Windward Hills Ave
Grand Forks, ND 58201

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Friday, December 18, 2009 11:40 AM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: staceydohn@cableone.net [mailto:staceydohn@cableone.net]
Sent: Friday, December 18, 2009 11:39 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Stacey Dohn
905 7th street south
Fargo, ND 58103

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Friday, December 18, 2009 4:28 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: ann.nelson@gmail.com [mailto:ann.nelson@gmail.com]
Sent: Friday, December 18, 2009 3:34 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Ann Nelson
10338 S Wood St.
Apt 1B
Chicago, IL 60643

Bachman, Tom A.

From:	O'Clair, Terry L.
Sent:	Monday, December 21, 2009 4:53 PM
To:	Bachman, Tom A.
Subject:	FW: Regional Haze Plan

-----Original Message-----
From: amp_2010@msn.com [mailto:amp_2010@msn.com]
Sent: Monday, December 21, 2009 4:47 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Adam Petty
1902 26 1/2 Court S
Fargo, ND 58103

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Friday, December 18, 2009 10:28 AM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: stewart.m.preston@gmail.com [mailto:stewart.m.preston@gmail.com]
Sent: Thursday, December 17, 2009 10:34 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Stewart Preston
PO Box 301
Medora, ND 58645

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:26 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: twotails100@hotmail.com [mailto:twotails100@hotmail.com]
Sent: Thursday, December 17, 2009 1:05 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
marcella gilbert
910 brooklawn dr
brookings, SD 57006

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:25 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: rcsailer@beu.midco.net [mailto:rcsailer@beu.midco.net]
Sent: Thursday, December 17, 2009 11:24 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
randy sailer
1018 cherry lane
beulah, ND 58523

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:24 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: dborman@att.net [mailto:dborman@att.net]
Sent: Thursday, December 17, 2009 10:48 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Darold Borman
1508 N Oakridge Place
Sioux Falls, SD 57110

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Thursday, December 17, 2009 4:24 PM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: pjacobs289@aol.com [mailto:pjacobs289@aol.com]
Sent: Thursday, December 17, 2009 9:37 AM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for considering my comments.

Sincerely,
Paul Jacobs
11001 221st Ave.
Morristown, SD 57645

Bachman, Tom A.

From: O'Clair, Terry L.
Sent: Monday, December 28, 2009 8:23 AM
To: Bachman, Tom A.
Subject: FW: Regional Haze Plan

-----Original Message-----
From: act3@goldenwest.net [mailto:act3@goldenwest.net]
Sent: Saturday, December 26, 2009 6:43 PM
To: O'Clair, Terry L.
Subject: Regional Haze Plan

Director Terry O'Clair
North Dakota Dept. of Health, Div. of Air Quality
918 E Divide Avenue, Second Floor
Bismarck, ND 58501-1947

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Thank you for the opportunity to comment on North Dakota's proposed regional haze plan. As a national park visitor and advocate for the parks, I value the beauty of Badlands, Theodore Roosevelt, and Wind Cave National Parks. I understand that the state's haze plan offers an unprecedented opportunity to clean up the air in these parks, which are affected by pollution from power plants and other industry. Air pollution from North Dakota's coal plants and industry also impacts national parks in Minnesota and Michigan, as well as four large wilderness areas.

The Clean Air Act requires old power plants and factories to reduce haze-causing pollutants. Technology exists to reduce this pollution--technology that will protect our national parks and wilderness areas, and public health. It is important that the Act and other air quality regulations are followed, so that we can enjoy these parks now and preserve them for our children and grandchildren.

The State of North Dakota can and should do more to protect our air quality as it implements the Regional Haze Rule. I request that the haze plan impose stricter limits on pollution from power plants and other industrial sources. In particular, North Dakota should require all appropriate coal plants to install more effective pollution control devices, and more aggressively pursue identified emission reductions from all sources.

Without this and other measures, North Dakota's coal plants will continue to unnecessarily obscure views in our national parks and wilderness areas for decades to come and deter tourists, including me and my family, from visiting the state of North Dakota and the beloved parks in the region. North Dakota must do its part to ensure that the air in our parks, and throughout the region, will indeed be restored to natural conditions.

Thank you for considering my comments.

Sincerely,
Andrea Yarger
26914 Battle Mountain Pkwy
Hot Springs, SD 57747

Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave
Bismarck, ND 58501-1947

8 January 2009

Dear Terry O'Clair:

I'm writing to submit a comment regarding the recent draft of the North Dakota State Implementation Plan (SIP) to reduce haze. Given the fact that the Theodore Roosevelt National Park is protected from man-made haze in the Clean Air Act and that man-made pollution from North Dakota power plants and industry is contributing to the haze in our national parks, it is very important that the ND SIP be revised to strengthen the regulations on our local coal-fired power plants. Burning approximately 30 million tons of coal each year, they are a major source of haze for our state and a substantial risk to our citizens' health.

The Clean Air Act requires ND to create a plan to reduce air pollution contributing to that haze, however ND's draft plan released last week fails to require strict enough limits for our state's largest pollution sources: the eight aging power plants, many of which were grandfathered in, therefore they have been allowed to pollute much more than the Clean Air Act's standards target. It is crucial for our state to use this moment to make the long-needed change and be more aggressive about protecting our people and natural resources, especially the quality of our air, land and water. Reducing air pollution from burning coal is the crucial step in protecting all three of these areas, since what goes up into the air inevitably ends up in our soil and water, thus in our citizens' bodies.

I ask that you revise and increase the controls in the SIP not only to protect our land and citizens, but also to protect and stimulate our sustainable economy. In every way, moving away from fossil fuels will benefit our state economically. It will force coal plants to move into sustainable- and in the long run- more inexpensive and profitable sources of energy. The price of burning fossil fuels will continue to rise as we start to pay for the externalities and as the international and national laws become stronger, which they are and are projected to continue to do. The income from green and sustainable energies, which ND has an abundant supply of, is continually rising and projected to rise. ND has already seen millions and even hundreds of millions of dollars invested in its wind farms, which needs to be further encouraged. A PEW study in 2009 stated that jobs in renewable energy outnumber jobs in the regular sector in ND by a margin of 3-to-1. So, raising the limits on coal may appear to be an economic loss in the short term, but it will certainly stimulate greater economic benefits, and a more stable future economy for our state in the long term.

Tourism is another aspect of our ND economy that we have to remember when considering revisions to the SIP. Tourism is such a large part of our ND economy, so we really need to protect our natural ecosystems from pollution in order to preserve these areas, as well as protect the people's health who visit them and keep the visibility as clear as possible so people can experience the majesty of these beautiful views. Every year I camp and hike in the Theodore Roosevelt National Park. The park is very important to me and many people I know. The friends I've taken there from out-of-state are always impressed by the visibility and "how far they can see", so it is really something we need to take seriously and protect from haze. In closing, I'd like to reiterate that this is both a health issue as well as an economic issue for our state, and the coal plants' pollution threatens them both.

For these and many other common sense reasons, I urge the ND State Health Department to revise and strengthen the air pollution controls in the ND SIP.

Thank you for hearing my request.

Sincerely,

James Kambeitz

James Kambeitz

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USA FIRST-CLASS FOREVER

ND DH Division of air qu.
918 E. Divide Ave
Bismarck, ND 58501

5850131947

HANDYMAN CLUB OF AMERICA

Dear Sir:

I feel there is no problem with the air qua. in N Dak.

Thank you

Richard

JAN 2010
Received
Air Quality
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31

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MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

January 7, 2010

Mr. Terry O'Clair
Director
Division of Air Quality – 2nd Floor
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Re: Comments on the North Dakota Department of Health Proposed Amendment to the State Implementation Plan (SIP) for Reducing Regional Haze

Dear Mr. ~~O'Clair~~ Terry:

Montana Dakota Utilities Co. (Montana-Dakota) submits the following comments on the North Dakota Department Health's (NDDH) proposed amendment to the State Implementation Plan (SIP) for reducing Regional Haze.

Montana-Dakota generates, transmits and distributes electricity and distributes natural gas in North Dakota, South Dakota, Montana and Wyoming. The company owns and operates electric steam generating facilities which are subject to extensive regulation under the Federal Clean Air Act. The following comments concern issues pertaining to R.M. Heskett Station Unit 2 (Heskett Unit 2) in the draft Regional Haze SIP.

Level of Emission Reduction from Voluntary Commitment

The NDDH included language in the last paragraph of Section 7.3.4 of the SIP, page 68, discussing a voluntary commitment by Montana-Dakota to reduce potential sulfur dioxide emissions in the future from Heskett Unit 2 by a minimum of 70 percent. The NDDH states in the SIP document that this commitment will reduce sulfur dioxide emissions to 1,660 tons per year at Heskett Unit 2 from its 2000-2004 emissions of 2,400 tons per year, yielding a 740 tons per year reduction. Montana-Dakota has calculated a projected average annual reduction of sulfur dioxide emissions of 474 tons per year that better represents the 70 percent reduction of sulfur from coal to stack during a normal operating year when adding limestone. This value, instead of 740 tons per year, should be used and is further explained in the following paragraphs.

The 2,400 tons per year NDDH cited in the SIP is an average sulfur dioxide emissions rate over the 2000-2004 time period. During this period, emissions varied from a minimum of 1,778 tons per year in year 2000 to a maximum of 2,754 tons per year in year 2004. The lower annual emissions are mainly due to plant shut downs, while the higher annual emissions are due to increased demand growth over time.

Montana-Dakota calculates the expected sulfur dioxide emission reduction by comparing emissions projected for a normal operating year when adding limestone to Heskett Unit 2 to the average sulfur dioxide emissions resulting from the higher operating years in 2000-2004. The higher emissions years are 2001 at 2,625 tons, 2003 at 2,650 tons, and 2004 at 2,754 tons, yielding an average of 2,676 tons of sulfur dioxide for a baseline annual average emissions rate.

To calculate the projected annual average sulfur dioxide emission rate for a normal operating year when adding limestone, Montana-Dakota made the following determinations and calculations. First, the average sulfur in coal from the 2000-2004 time period was approximately 0.72 percent, with an average heat content of the coal at 7,176 btu/lb. We then used Equation 19-25 from EPA Method 19 to calculate an average uncontrolled sulfur dioxide emission rate of approximately 2.01 lb/mmbtu. With limestone addition, Heskett Unit 2 could achieve a sulfur dioxide emission rate of approximately 0.60 lb/mmbtu, which assumes a 70 percent level of control from the uncontrolled emission rate of 2.01 lb/mmbtu. During a normal operating year with limestone addition, and assuming an approximate 91% availability (representing the average availability in 2001, 2003 and 2004), Heskett Unit 2 would be expected to emit approximately 2,202 tons of sulfur dioxide per year (2.01 lb/mmbtu x 916.5 mmbtu/hr x 7,971 hr/year (annual 91% availability) / 2000 lb/ton x 30% = 2,202 ton/year).

Based on the above, Heskett Unit 2 would expect to achieve an average annual sulfur dioxide emissions reduction of approximately 474 tons per year, which reflects the baseline emissions of 2,676 tons per year less the projected 2,202 tons per year with limestone control. If the NDDH should choose to include in the Regional Haze SIP a projected sulfur dioxide emission reduction associated with Montana-Dakota's voluntary commitment, Montana-Dakota could only support a projected average annual reduction of 474 tons per year.

Supporting SIP Documentation for Heskett Unit 2

We assume that the Appendices A.2 and A.3 to the final Regional Haze SIP will be updated and revised to include copies of: (1) the document titled, "CALPUFF Visibility Modeling Protocol: MDU Heskett Unit 2 BART Analysis" prepared by AECOM and dated November 25, 2009; (2) the NDDH and EPA Region 8 approvals of the November 25, 2009 BART modeling protocol for Heskett Unit 2, which include an e-mail from S. Weber, NDDH, to B. Paine, AECOM dated December 1, 2009, an e-mail from S. Weber, NDDH to K. Golden, EPA Region 8, dated December 1, 2009, and an e-mail from K. Golden, EPA Region 8, to S. Weber, NDDH, dated December 10, 2009); (3) a copy of the document titled "Updated BART CALPUFF Visibility Modeling Analysis for Montana-Dakota Utilities Heskett Station Unit 2," dated December 17, 2009, which sets forth the most recent visibility modeling analysis for Heskett Unit 2 (this document is currently included in the draft Regional Haze SIP documents, however, it is located at the bottom of the NDDH's webpage http://www.ndhealth.gov/AQ/RegionalHaze/); and (4) the December 21, 2009 NDDH correspondence to EPA Region 8 which states that Heskett Unit 2 is exempt from BART.

Reasonable Further Progress Goals

The federal Regional Haze Rules require NDDH to set reasonable progress goals (RPGs) toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The federal rules identify four factors that must be considered in evaluating potential added emission control measures to meet RPGs, including: (1) the cost of compliance; (2) the time necessary for compliance; (3) energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any existing source subject to such requirements. See e.g., "Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota," dated May 18, 2009, Revised Draft Report Prepared by: B. Nelson, W. Battye, and J. Hou, EC/R Incorporated.

As part of applying the RPG analysis to Heskett Unit 2, Montana-Dakota expects the NDDH to consider the degree of visibility improvement on a deciview (dv) basis and a cost per deciview improvement basis ($/dv) that would result from additional controls, since this is the approach the NDDH followed when evaluating emissions from other RPG sources in the State. At the public hearing held today on the proposed Regional Haze SIP, we understood NDDH to confirm that Heskett Unit 2 has been subject to RPG analysis. The analysis considered the degree of deciview improvement that would result from a 95 percent level of sulfur dioxide emission control. The analysis showed inconsequential deciview improvements at Theodore Roosevelt National Park (0.009 dv) and at Lostwood National Wildlife Refuge (0.003 dv). Based on the outcome of the analysis, NDDH stated that it would not require additional controls for Heskett Unit 2 under the RPG element of the SIP. While Montana-Dakota endorses this outcome, analyzing the incremental costs of control per deciview improvement would further support the NDDH's RPG conclusions with respect to Heskett Unit 2.

If you have any questions or would like to discuss our comments, please contact me at 222-7844.

Sincerely,

Abbie Krebsbach
Environmental Manager

cc: Andrea Stomberg, Vice President Electric Supply
Alan Welte, Generation Manager
Tony Stroh, R.M. Heskett Station Manager

United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

January 8, 2010

N3615 (2350)

Mr. Terry L. O'Clair, P.E.
Director
Division of Air Quality
North Dakota Department of Health
Environmental Health Section
918 E. Divide Avenue
Bismarck, North Dakota 58501-1947

Dear ~~Mr. O'Clair~~ Terry:

We appreciate the effort you and your staff have devoted to responding to the comments we provided during consultation on your State Implementation Plan (SIP) revision to address regional haze requirements of 40 CFR 51.300-308. However, after reviewing your "Response to DOI Comments" document, we believe that there are still some outstanding issues that warrant further consideration as you prepare the SIP revision for submittal to EPA Region 8. Specifically, we still contend that Theodore Roosevelt National Park (NP) should be treated in all impact assessments as one Class I area (not three separate areas), and that additional controls (e.g., Selective Catalytic Reduction) is Best Available Retrofit Technology (BART) for some BART-eligible units. Our follow-up comments are discussed in more detail below and in the enclosed document.

<u>Treatment of Theodore Roosevelt NP</u>

We appreciate your acknowledgement that Theodore Roosevelt NP is only one Class I area under the Clean Air Act. However, we disagree that units of the park can be separated when assessing visibility impairment for the purposes of determining if an existing source causes or contributes to visibility impairment under the Regional Haze Rule. Your response cites the definition of "adverse impact on visibility" which is a definition that applies for assessment under Section 51.307 regarding impacts of new sources. For purposes of applying Best Available Retrofit Technology (BART) to existing sources, or determining if an existing source could be controlled to aid in "reasonable progress" toward the national visibility goal of no human-caused impairment, a State should consider if a source contributes to "visibility impairment." Section 51.301 (x) defines visibility impairment as "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions." U.S. Environmental Protection Agency rules for applying BART establish a test for "contribution" of sources as 0.5 deciview impact for the 98th percentile day over a three-year period. That impact applies to all locations (i.e., receptors) within a Class I area for the modeled three-year period. In the case of Theodore Roosevelt NP, modeling receptors are only located within the boundaries of the three individual units of the Class I area. Since lands outside of the Class I area are not included in assessing the 0.5 deciview impact, there is no misrepresentation of impacts for park visitors, and there is no extension of Class I status to areas outside of the park.

If receptors within the total park boundary show 0.5 or more deciview impacts (98th percentile day) over the three-year period, a BART-eligible source's emissions contribute to "visibility impairment" and must be assessed under EPA's regional haze BART guidance. We believe that this test is useful for any stationary source to identify those sources or groups of sources that should be evaluated for reasonable progress as well.

<u>Best Available Retrofit Technology (BART) Analyses</u>

We have reviewed the responses you provided to our comments on assessing BART controls. The enclosed follow-up comments supplement the concerns we have raised in light of your responses.

We have received a letter dated December 21, 2009, regarding new results of air quality modeling to determine if the Heskett Power Plant is subject to BART. We are coordinating with U.S. EPA Region 8 staff in their efforts to verify the new modeling results. Pending the outcome of the review, we may provide additional comments on these new modeling results.

Finally, we have recently become aware that Regenerative Selective Catalytic Reduction (SCR) is an available technology that is applicable to Electric Generating Units and has the potential to allow SCR to be installed on a relatively cool gas stream (e.g., following a scrubber) with relatively little auxiliary heat required. The primary drawbacks to this Regenerative SCR are the capital cost and space requirement, but this technology warrants further evaluation as possible BART for North Dakota sources.

Again, we appreciate your State's efforts to build a foundational SIP for the purposes of addressing regional haze and visibility protection in general for our national treasures. We look forward to working with the State to continue progress toward the national visibility goal.

Sincerely,

John Bunyak

for Christine L. Shaver
Chief, Air Resources Division
National Park Service

Sincerely,

Sandra V. Silva

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service

Enclosure

cc:
Tom Bachman
Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Callie Videtich
U.S. EPA Region 8
1595 Wynkoop Street
Mail Code: 8P-AR
Denver, CO 80202-1129

Department of the Interior (DOI) Follow-up Comments on North Dakota Department of Health (NDDH) Best Available Retrofit Technology (BART) Analyses
January 8, 2010

DOI Comment 6: (Purpose of the BART Program)
The core purpose of the BART program is to improve visibility in our Class I areas. BART is not necessarily the most cost-effective solution. Instead, BART represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. We believe that it is essential to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected.

NDDH Response: In determining BART, visibility improvement was generally not weighted as heavily as the cost of compliance because we believe the single source modeling required by the BART guideline does not give a true representation of the degree of improvement in visibility **which may reasonably be anticipated to result from the use of the technology.**

We believe the cumulative visibility effects analysis promoted by DOI is scientifically unsound and not in accordance with rule or law. Adding the maximum improvement value (or 98th percentile) at one Class I area to the maximum improvement at another Class I area does not account for these maximums happening at different times. In addition, DOI has not defined which Class I areas should be added together to achieve the cumulative impact. This makes the analysis arbitrary. The single source modeling under BART does not provide a realistic estimate of visibility improvement of a given technology. Creating a "cumulative effects" analysis based on the flawed BART analysis only compounds the inaccuracy and misleads the reader of the SIP.

In addition, the BART Guideline only requires an evaluation of the change at each receptor. It does not require adding these changes together.

DOI Follow-up: In light of the NDDH's perceived problems with the suggested DOI approach, the NDDH should explain how it considered the benefits of reducing emissions with respect to visibility improvements at multiple Class I areas.

DOI Comment 8: The ability of SCR to reduce emissions, as assumed by NDDAQ, was inconsistent and sometimes underestimated.

NDDH Response: In the ANPR for the Four Corners Power Plant (Federal Register 8/28/09) EPA states "APS estimated that SCR could achieve NO_x control of approximately 90% or greater from the baseline emissions. For new facilities, 90% or greater reduction in NO_x from the SCR can be reasonably expected. See May 2009 White Paper on SCR from Institute of Clean Air

Companies. For SCR retrofits on an existing coal-fired power plant, Arizona Department of Environmental Quality (ADEQ) determined that 75% control from SCR (following upstream reductions by LNB) was appropriate for the Coronado Generating Station in Arizona. Based on this data, EPA has determined that an 80% control efficiency for SCR alone, rather than the 90+% control assumed by APS, is appropriate". The Department believes 80% is a reasonable estimate that allows the source to comply with the expected emission limit on a continuous basis.

DOI Follow-up: We have advised EPA Region 9 that it has underestimated the ability of SCR to reduce NO_x emissions from the sources in question and supported our comments with real-world data from actual retrofits to coal-fired EGUs. Our comments can be found in the same docket accessed by NDDH.

DOI Comment 9: The cost of SCR was consistently overestimated.

NDDH Response: The DOI used the EPA Air Pollution Control Cost Manual (February 1996) to estimate the capital cost and operating costs for the SCR system. The DOI did not use the most current version of this manual which is dated January 2002.

DOI Follow-up: We used the current version of the Cost Manual as it pertains to SCR.

NDDH Response: The EPA Air Pollution Control Cost Manual (both versions) is significantly out-of-date for estimating costs for SCR. This can be seen from the recently published results of EPA's review of the Four Corners Power Plant BART analysis. In the Advanced Notice of Proposed Rulemaking (August 28, 2009), EPA published the Consultant's, EPA's and the National Park Service's estimate of the cost for NO_x controls.

DOI Follow-up: We have advised EPA Region 9 that it has overestimated the cost of SCR to reduce NO_x emissions from the sources in question. Our comments can be found in the same docket accessed by NDDH.

NDDH Response: It would appear the NPS is underestimating annualized SCR costs by as much as a factor of 6 and cost effectiveness by as much as a factor of 3. The discrepancy between the annualized cost and the cost effectiveness is apparently due to the NPS overestimating the effectiveness of SCR. Based on this apparent underestimation, it appears the costs provided by the consultants and the Department's estimates are similar to EPA estimates and are reasonable. Any estimate by the FLM of cost on a dollar per deciview basis would be similarly flawed.

DOI Follow-up: NDDH should conduct an independent analysis by applying the EPA-recommended OAQPS Control Cost manual.

NDDH Response: As pointed out earlier, the OAQPS Control Cost Manual is out-of-date. EPA accepted estimates based on the CUE Cost Model for the Four Corners Power Plant BART analysis. Since the OAQPS Control Cost Manual is out-of-date and drastically underestimates control costs, we believe the CUE Cost Model provides a more realistic estimate of the costs.

DOI Follow-up: EPA Region 8 recommended that NDDH use the OAQPS Control Cost manual, and we support the EPA position on this matter.

DOI Comment 10: (Step 5: Visibility Improvement)
A) DOI believes it is appropriate to consider both the degree of visibility improvement as well as cumulative effects.
B) DOI is concerned that the Department did not provide the total improvement for each BART option.

NDDH Response: The total improvement under BART is not the best metric for addressing visibility associated with each option since the single source modeling under BART over predicts (by a factor of 5-7) the actual improvement in North Dakota. Incremental differences in improvement provides an easy way to evaluate the visibility improvement benefits of one option over another. The difference is equivalent to the total improvement of one option minus the total improvement of the other option. Providing the total improvement will mislead the reader of the SIP because of the over prediction. However, this information can be extracted from the analyses conducted by the operators of the BART sources. .

DOI Follow-up: NDDH is placing too much emphasis upon incremental differences; NDDH should provide the total improvement. In addition, we do not understand how NDDH can claim that the BART modeling over predicts (by a factor of 5-7) because in the Leland Olds Station Unit 1 and 2, and the Milton R. Young Unit 1 and 2 BART protocols, NDDH itself states: "The NDDH modeling protocol recommends a specific version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of LOS / MRYS. ... The input files contained the specific coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters that the NDDH has determined best represents the region. The NDDH version of CALPUFF was used for modeling." Therefore, NDDH should support its claims that "the single source modeling under BART over predicts (by a factor of 5-7) the actual improvement in North Dakota."

DOI Comment 10: C) DOI is concerned about the difference in their modeling for Leland Olds Unit 2 and the Department's and Basin Electric's modeling results (the latter two sets of results agree closely).

NDDH Response: There are bound to be differences in modeling results when different model settings and options are used as well as different receptor grids. One error noted in the DOI modeling results was the input for the maximum 24-hour SO_2 emission rate for Unit 2. DOI used 17,610 lb/hr plus 1,581 lb/hr for sulfate. Unit 2 had a maximum 24-hour SO_2 (includes SO_4) of 12,205 lb/hr during the baseline period (2000-2004). DOI apparently used an SO_2 + SO_4 emission rate based on maximum future sulfur content. This is incorrect since current visibility conditions (12,205 lb/hr) are compared to conditions after controls are applied. The BART Guideline states "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)". The meteorological data used by the Department is from 2000-2004. Use of potential future uncontrolled emissions for the precontrol scenario is inconsistent with the BART guideline. The Department also noted that this error carried over into the emission rates for other pollutants. This error will provide a much greater improvement in visibility as found by the DOI.

DOI Follow-up: We agree with NDDH's method of assessing future emissions and control costs and effectiveness based upon anticipated changes in coal quality. We, therefore, believe that it is appropriate to model changes in visibility impairment on the same bases. The SO_2 emission rate was provided by Basin Electric in "Table 1.3-2 – Leland Olds Station Future PTE Emissions for BART Analysis". The sulfate emissions were derived from our PM speciation workbook and account for all condensible inorganic emissions. We invite NDDH to discuss this matter further.

DOI Comment 11: It appears to be more beneficial to reduce NO_x than to reduce SO_2 in this cool climate.

NDDH Response: The Department does not necessarily agree with this statement. There are situations in North Dakota where reduction in NO_x has very little impact on visibility. This can be seen from the AVS I analysis. A 65% reduction NO_x (2,356 tpy) only provided a 0.01 deciview improvement in the average of the 20% worst days.

DOI Follow-up: AVS 1 was not subject to BART, and thus not reviewed in that context. If one considers the relative visibility benefits of reducing SO_2 versus NO_x (on a per-ton basis) at a given EGU that was subject to BART, it appears to be more beneficial to reduce NO_x than to reduce SO_2 in this cool climate.

DOI Comment 12: DOI recommends more emphasis on the dollar per deciview metric.

NDDH Response: There was no established data base for this metric when the BART analyses were developed and when the Department was making its decisions. Even the DOI's data is not very useful since the EPA has not approved the BART determinations in that database. Again, the single source modeling does not reflect the true visibility improvement. It may be more realistic in some states than in others. Therefore, the comparison of $/deciview in North Dakota to $/deciview in another State is not an apples-to-apples comparison. The Department has considered the incremental visibility improvement between BART options. We believe this is the best metric given the limitations of single source modeling to provide realistic estimates of visibility improvement.

DOI Follow-up: NDDH has placed too much emphasis upon incremental differences and should explain what benchmarks or thresholds it used to make its decisions. As for the differences among state modeling procedures, the cost-per-deciview criterion we have suggested is simply the estimated cost divided by the estimated improvement—how that value is derived is irrelevant in this context—it is how the value is used that matters.

DOI Comment 13: For several units, NDDOH is proposing alternative sulfur dioxide (SO_2) limits that are similar to the presumptive BART limits because they allow a source to choose between a limit in terms of pounds of emissions per million Btu of heat input, or percent reduction of that pollutant. While EPA presented its BART Guidelines for SO_2 in that format, we do not believe that it was EPA's intention to allow the source to choose the more favorable limit. By definition, BART represents the highest degree of control that meets the five-factor test. Where NDDOH has determined that a lb/mmBtu limit is reasonable, it should require that that limit be met.

Similarly, where NDDOH has determined that a percent reduction limit is reasonable, it should require that that limit be met. If both limits are determined to be reasonable, then to allow the source to choose only one clearly does not represent the most stringent reasonable degree of control. Therefore, where NDDOH has proposed alternative limits, both should be required.

NDDH Response: The DOI has requested that the sulfur dioxide limitations be written as 95% reduction and 0.15 lb/10^6 Btu instead of 95% reduction or 0.15 lb/10^6 Btu. Coal quality data suggests that the source may not be able to comply with the 0.15 lb/10^6 Btu limit when the maximum sulfur coal is received. This would make the requested standard impossible to meet for high sulfur coal. The BART guidelines (40 CFR 51, Appendix Y, Section IV.E.4) states "you must require 750 MW power plants to meet specified levels of SO_2 of either 95 percent control or [emphasis added] 0.15 lb/10^6 Btu". The guidance does not indicate both standards apply. In addition, the BART presumptive levels are not applicable to any source in North Dakota except for NO_x at Coal Creek Station.

DOI Follow-up: There is also a fundamental problem with setting only a percent-reduction limit on SO_2 emissions. If fuel sulfur content increases, emissions can increase correspondingly. Unless sulfur content is limited, or a cap is placed on mass emissions (e.g., lb/hr, tons/yr as proposed by Wyoming, for example), the actual amount of SO_2 emitted is unlimited.

NDDH Response: The DOI has also asked that a mass per unit of time limit be placed on the permit for SO_2. The Department believes this is unnecessary since the Department's evaluation of visibility impacts was based on full load and worst case sulfur (i.e. highest 24-hour emissions). The Department asked the EPA if a mass per unit of time limit (24-hour basis to ensure the accuracy of the modeling) was necessary in the permit that establishes the BART limits. In a November 21, 2005 response from Laurel Dygowski of Region 8, it was stated "we think that a 24-hour limit is unnecessary and may not be of much value". Based on EPA's guidance and the Department's determination that mass per unit of time units are not necessary, the Department will not include such limits in the permit that establishes the BART limits.

DOI Follow-up: As we noted previously, even if coal quality deteriorates to the anticipated worst-case, the proposed control technology would still be capable of meeting the lower lb/mmBtu limit.

DOI Comment 25: On page 16 of the comments, the DOI states, "We believe that higher control efficiency is warranted for both the lignite and PRB sub-bituminous scenarios". The DOI goes on to state that a facility burning coal with an uncontrolled SO_2 emission rate of 2.4 lb/MM Btu for lignite and 1.6 lb/MMBtu on PRB "should be capable of at least 93% control and achieve an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis[11]". Footnote 11 in the DOI comments states, "Please see the entry in Appendix D for the permit issued by Wyoming to Black Hills Power for its WYGEN3 project".

NDDH Response: The DOI states a SD/FF at Stanton #1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis. The DOI attempts to support this position by referencing the WYGEN3 facility permit. Although the WYGEN3 facility does have a 0.09 lb/MMBtu SO_2 emission limit, according to the EPA RACT/BACT/LAER clearinghouse, the 0.09 lb/MM Btu SO_2 emission limit is on a 12-month rolling average basis, not a 30-day rolling average basis. Also, the RACT/BACT/LAER clearinghouse does not list a required SO2 removal efficiency. If the WYGEN3 facility burns low-sulfur coal, the facility could comply with the 0.09 lb/MMBtu emission limit with SO_2 control efficiencies below 90%. Furthermore, it is the Department's understanding that the WYGEN3 facility has yet to operate and demonstrate that the SO_2 emission limit can be achieved. Based upon these facts, the WYGEN3 facility permit does not support the DOI position that a SD/FF at Stanton Station Unit 1 "should be capable of" at least 93% control and an emission limit of 0.09 lb/MMBtu on a 30-day rolling average basis. The Department maintains the position that a SD/FF operating at Stanton Station Unit 1 is capable of achieving an SO_2 control efficiency of 90%.

DOI Follow-up: The WYGEN3 permit[1] limits the EGU to 117 lbSO_2/hr on a 30-day rolling average basis. At a heat input of 1,300 mmBtu/hr, this corresponds to 0.09 lb SO_2/mmBtu on a 30-day rolling average.

DOI Comment 26: On page 16 of the DOI comments, the DOI states, "Because the larger Stanton Unit #10 also located at this site is achieving less than 0.06 lb/MMBtu on an annual basis (presumably burning PRB coal) using the same SD/FF technology proposed for Stanton Unit #1, NDDAQ should explain why a newer installation of that technology at Stanton #1 cannot perform as well, at least on PRB coal".

NDDH Response: The DOI incorrectly states that Stanton #10 is larger than Stanton #1. In fact, Stanton #10 (with a heat input of approximately 642 MM Btu/hr) is approximately 2.8 times smaller than Stanton #1 (with a heat input of approximately 1,800 MM Btu/hr). The DOI states that Stanton #10 emitted SO_2 at an emission rate of 0.06 lb/MM Btu and asks the Department to explain why Stanton #1 cannot perform as well as Stanton #10 when burning PRB coal. Although the Stanton #10 facility has recently emitted SO_2 at an emission rate of 0.06 lb/MM Btu, based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton #10 is estimated to be approximately 90%. The dry scrubber technology proposed as BART for Stanton #1 is expected to achieve an SO_2 control efficiency of 90%, so Stanton #1 will be expected to perform as well as Stanton #10.

DOI Follow-up: We appreciate NDDH's correction of our error with respect to the relative sizes of the two EGUs. However, this does not change our contention that Stanton #1 should be able to perform as well as Stanton #10, both on lb/MMBtu and control efficiency bases. NDDH should show how it arrived at the conclusion that "based upon the average sulfur content of the coal burned the SO_2 removal efficiency at Stanton #10 is estimated to be approximately 90%."

DOI Comment 29: On page 17, the DOI states, "We believe that NDDAQ should have included SOFA with tail-end SCR with reheat in its analysis".

NDDH Response: The Department analyzed SCR with reheat in the BART analysis. A 90% control efficiency for SCR with reheat was assumed. For retrofits, the Department believes that a 90% control efficiency for SCR with reheat is highly optimistic and that 80% control is

[1] http://deq.state.wy.us/eqc/orders/Air%20Closed%20Cases/07-2801%20Dry%20Fork%20Station/DEQ's%20Dispositive%20Response.63-Ex.16.pdf

reasonable. It should be noted that conducting the BART analysis using an 80% control efficiency would make the cost of SCR with reheat even more cost prohibitive.

In the Department's judgment, SOFA with SCR with reheat would not attain greater than 90% NO_x control at Stanton #1. Since SOFA with SCR with reheat would be more expensive than SCR with reheat (which has already been determined to be cost prohibitive assuming a 90% control efficiency), it can be concluded that an analysis of SOFA with SCR with reheat would also be considered to be cost prohibitive.

DOI Follow-up: NDDH cannot assume that "SOFA with SCR with reheat would be more expensive than SCR with reheat" on a total annual cost basis without doing a proper cost analysis. It is possible that the additional capital cost (on an annual basis) of adding SOFA would be more than offset by reduced annual operating costs.

DOI Comment 30: On pages 18 and 20 the DOI indicates that the expected costs for SCR with reheat included in the BART analysis for Stanton #1 are higher than the cost estimates prepared by the DOI. The DOI requests that NDDH document and justify the SCR-with-reheat cost estimate.

NDDH Response: The DOI requests that the Department document and justify the SCR with reheat cost estimate for Stanton #1. The Department considers the cost estimate of SCR with reheat submitted with the GRE BART analysis to be extensively documented and the Department has verified the cost estimates.

DOI Follow-up: NDDH should explain how it "verified the cost estimates".

DOI Comment 34: DOI believes SOFA + SCR can achieve 83% NO_x removal.

NDDH Response: As pointed out in the Advanced Notice of Proposed Rulemaking for the Four Corners Power Plant, the Arizona DEQ determined that 75% control was appropriate following low NO_x burners at the Coronado Generating Station. Leland Olds 1 is equipped with low NO_x burners. We believe 75% reduction for the retrofit of a 43 year old plant is appropriate. Reducing the emission rate to 0.05 lb/10^6 Btu achieves 212 tons per year additional NO_x reduction. The cost effectiveness is then $8,888/ton to $12,784/ton. These costs are still considered excessive and SCR + SOFA is not BART.

DOI Follow-up: We have advised EPA Region 9 that it has underestimated the ability of SCR to reduce NO_x emissions from the sources in question and supported our comments with real-world data from actual retrofits to coal-fired EGUs. Our comments can be found in the same docket accessed by NDDH. Furthermore, NDDH cannot simply halt the BART

process by determining that a technically feasible option is too expensive on a cost-per-ton basis. A full five-factor BART analysis is required.

DOI Comment 35: NDDAQ did not evaluate the visibility benefits of any of the technically feasible options except for the proposed basic SOFA + SCR.

NDDH Response: The cost analysis eliminated SCR, coal reburn + SCR, coal reburn + SOFA and SNCR + boosted SOFA on either a very high cost effectiveness basis or a very high incremental cost basis. This left SOFA + SNCR as the most efficient control option. This option was then modeled to determine the visibility effects.

DOI Follow-up: NDDH cannot simply halt the BART process by determining that a technically feasible option is too expensive on a cost-per-ton basis. A full five-factor BART analysis is required.

DOI Comment 37: Based upon NDDAQ's analysis, addition of the proposed basic SOFA+SNCR to LOS #1 yields a cost-effectiveness of $25.6 million per dv at Theodore Roosevelt NP and $13.2 million per dv cumulatively when Lostwood WA is included. NDDAQ has not adequately considered the visibility benefits of the control strategies it evaluated. NPS' analysis of addition of basic SOFA+SCR with reheat yields a cost-effectiveness of $12.6 – $32.3 million per dv cumulatively. We would normally consider costs above $20 million/dv to be above the average that most states/source are proposing, but believe that these results warrant further analysis, as we will discuss in more detail with respect to LOS #2.

NDDH Response: SOFA + SCR has an estimated cost of $8,888 - $12,784/ton of NO_x removed. The incremental cost would be approximately $15,748/ton to $25,319/ton over the next most efficient option. It is clear that SOFA + SCR, or SCR alone, is not cost effective for this unit.

DOI Follow-up: NDDH cannot simply halt the BART process by determining that a technically feasible option is too expensive on a cost-per-ton basis. A full five-factor BART analysis is required.

<u>M.R. Young Station Unit 1</u>

DOI Comment 49: NDDAQ proposes that NO_x emissions be limited to 2,070.2 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

NDDH Response: The proposed limit is under normal operating conditions without the ASOFA and SNCR, since the SNCR cannot be operated until the proper boiler temperature is reached. The actual startup emissions will be much higher (>1.0 lb/10^6 Btu). Therefore, limiting startup emissions based on normal operations with SNCR (<0.35 lb/10^6 Btu) will provide no relief to the source during startup.

DOI Follow-up: To clarify our initial comment, we are suggesting that NDDH limit emissions on a lb/hr basis (not lb/mmBtu) to a rate equal to the maximum lb/hr that would be allowed were MRYS #1 to meet its BART limit under normal operation (e.g., BART limit in lb/mmBtu * maximum allowable heat input in mmBtu/hr). Thus, as load (and furnace temperature) increases, the effectiveness of the NO_x control technology also increases so as to stay under the lb/hr limit.

DOI Comment 51: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we also estimated a total annual cost for ASOFA + SCR with reheat at $9.7 million and a corresponding cost effectiveness of $1,028 per ton.

NDDH Response: Minnkota has provided its own estimate of the cost of SCR as part of the BACT process under their Consent Decree. Minnkota's estimate has been included in the BART determination.

DOI Response: We have not had sufficient time to properly evaluate the materials posted on or after November 25, 2009, by NDDH.

<u>M.R. Young Station Unit 2</u>

DOI Comment 54: NDDAQ proposes that NO_x emissions be limited to 3,995.6 lb/hr on a 24-hour rolling average basis during startup. We recommend that NDDAQ limit the mass emission rate (e.g., lb/hr) to the rate under normal operation.

NDDH Response: See response to Comment 49.

DOI Follow-up: To clarify our initial comment, we are suggesting that NDDH limit emissions on a lb/hr basis (not lb/mmBtu) to a rate equal to the maximum lb/hr that would be allowed were MRYS #2 to meet its BART limit under normal operation (e.g., BART limit in lb/mmBtu * maximum allowable heat input in mmBtu/hr). Thus, as load (and furnace temperature) increases, the effectiveness of the NO_x control technology also increases so as to stay under the lb/hr limit.

DOI Comment 56: NDDAQ overestimated the costs associated with adding SCR. In the absence of supporting documentation by NDDAQ, we estimated total annual costs for ASOFA+tail-end SCR with reheat at $15.6 million and a corresponding cost effectiveness of $898 per ton.

NDDH Response: Minnkota has provided a much more detailed cost estimate of SCR with reheat as part of their BACT process under their Consent Decree. This estimate has been used in the Department's BART determination.

DOI Follow-up: We have not had sufficient time to properly evaluate the materials posted on or after November 25, 2009, by NDDH.

DOI Comment 63: Table 9.9 summarizes the results of assessing the costs and visibility improvement associated with possible controls on these facilities. The two power generation facilities, Coyote and AVS, have emissions and Q/d impacts that are similar, if not greater than, BART sources that will be required to add controls. The methodology to calculate visibility improvements noted in Table 9.9 are not explained in this section but appear to be some calculation of changes in the long-term metric of the 20 percent worst visibility days. These sources likely contribute to higher impacts on a daily basis, and a reduction in their emissions would be part of a broad strategy to reach natural conditions at the Class I areas. As such NDDAQ should examine the total improvement from the suite of sources as part of its reasonable progress assessment, not a simple unit by unit approach.

NDDH Response: The improvement in the 20% worst days was used to indicate the amount of visibility improvement. The SIP was revised to better explain this. Addressing individual days under reasonable progress is inconsistent with the reasonable progress goals in 40 CFR 51.308(d)(1) which states "The reasonable progress goals must provide for improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period." 40 CFR 51.301 defines the most impaired days as meaning "the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the highest amount of visibility impairment." 40 CFR 51.301 defines the least impaired days as the average visibility impairment (measured in deciviews) for the 20% of monitored days in a calendar year with the lowest amount of visibility impairment." It is clear that reasonable progress goals should be established based on the average of the "most impaired days" and the "least impaired day", not individual days.

The Department did evaluate the cumulative effects of the most efficient remaining options. As stated on p. 182, the cumulative visibility improvement was 0.11 deciviews at LWA and 0.03 deciviews at TRNP. The less efficient control options would provide even less improvement.

DOI Follow-up: The use of daily impacts is a good means to identify those sources that have the largest impact on the 20 percent worst days. Since North Dakota is not meeting the uniform rate of progress for visibility improvement under EPA's guidance, it should seriously evaluate all significant sources of human-caused impairment. It is unclear if cumulative visibility improvement cited in the SIP included controls at Coyote and AVS.

Basin Electric Power Cooperative

Comment 1: Basin Electric believes LDSCR and TESCR are not technically feasible. They believe the Department should not rely on historical operating data of biomass boilers and should not rely on vendor's statements that they will provide performance guarantees for LDSCR and TESCR. Basin Electric believes LDSCR and TESCR are not commercially available for boilers that combust North Dakota lignite.

Response: The Department's analysis of this issue indicates that electrostatic precipitators, such as those at the Leland Olds Station, are capable of removing up to 99% of the sodium that is in the lignite combusted. The analysis also indicates that control of the submicron sodium and potassium aerosols will be greater than 90%. This indicates the flue gas characteristics will be no worse than cyclone boilers burning subbituminous coal in a high dust SCR configuration. It also indicates the concentration of potassium and sodium aerosols are less than pilot scale testing for biomass combustion which indicates an SCR can be successfully operated (Zheng et. al. 2008, Kling et. al. 2007). The commenter provided no evidence to dispute this point. Biomass contains soluble sodium and potassium just like North Dakota lignite. TESCR is being operated successfully on several biomass boilers.

Regarding vendor guarantees, the BART Guideline states "Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, we do not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, you should make decisions, about technical feasibility based on chemical, and engineering analyses (as discussed above), in conjunction with information about vendor guarantees." The information on vendor guarantees was only one portion of the evidence that was considered in making the technical feasibility determination. The commenter also suggested that pilot scale testing is necessary before LDSCR and TESCR can be determined to be technically feasible. The flue gas characteristics after an ESP when compared to pilot testing at biomass-fired boilers (Zheng et. al. and Kling et. al.) indicate LDSCR and TESCR can be successfully operated on North Dakota lignite. Pilot testing will help optimize the design of LDSCR or TESCR and provide a better estimate of catalyst life; however, the NDDH believes it is unnecessary for determining technical feasibility.

Comment 2: The commenter believes that BART NO_x controls that have a cost effectiveness greater than $1,350 per ton are unreasonable.

Response: The EPA has not established a "bright line" for determining whether BART controls are cost effective or reasonable. In the preamble to the proposed BART Guideline (F.R. Vol. 69, No. 87, p. 25198) EPA discussed this issue. This discussion indicates the WRAP technical support document for the Grand Canyon visibility Transport Report Annex listed control options are "low" below $500 per ton, "moderate" from $500 per ton to $3,000 per ton and "high" if over $3,000 per ton. This is a 1999 document and costs must be adjusted accordingly for inflation. The CAIR rule, which could have been used as a substitute for BART, had an estimated cost of up to $2,700 per ton (this rule has now been vacated). Based on the information cited, the NDDH believes the $1,350 per ton cost effectiveness is a reasonable BART cost.

Comment 3: The Department's conclusion (in the SIP), that the elimination of every in-state emissions source would still not achieve the 2018 reasonable progress (glide path) goal, is counterintuitive and is misleading on several fronts.

Response: Because the commenter provided no specific information on why this conclusion is "counterintuitive or misleading," the Department cannot directly respond. However, the Department believes that the modeling analysis supporting this conclusion makes a very strong and intuitive point about the relatively low contribution of North Dakota visibility-affecting emissions sources to visibility degradation in North Dakota Class I areas. Therefore, the Department stands by the conclusion.

Basin Electric, Great River Energy and Minnkota Power Coop.

Comment 1: The commenters want the SIP revised to redefine natural visibility conditions and reset the glide path for reasonable progress goals.

Response: For the current planning period and SIP, the Department does not have the time or resources to adjust natural visibility conditions and reset the uniform rate of progress glide path as suggested. However, the Department finds merit in this suggestion and will consider such adjustments in the next planning period.

Great River Energy

Comment 1: GRE agreed with the NDDH's modeling approach and encouraged the NDDH to use the most up-to-date modeling science and to calibrate these models with actual monitored data to ensure their relative accuracy.

Response: Agreed

Comment 2: GRE believes the NDDH must preserve its ability to adjust the glide path for non-manmade and international emissions.

Response: See response to Comment No. 1 under Basin Electric, Great River Energy and Minnkota Power Coop.

Comment 3:

(a) GRE believes site specific cost estimates provided by various consulting firms are more accurate than from cost manuals which are adjusted for inflation.

Response: Agreed

(b) GRE believes that approximately $1,000 per ton cost effectiveness should be used as a cutoff for BART determinations.

Response: See response to Basin Electric's Comment No. 2.

Attachments

1. Basin Electric's Comments.

2. Combined Comments of Basin Electric, Great River Energy and Minnkota Power Coop.

3. Great River Energy Comments.

BASIN ELECTRIC POWER COOPERATIVE

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January 8, 2010

Terry O'Clair, Director
Division of Air Quality
Environmental Health Section
North Dakota Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Basin Electric Power Cooperative Comments on proposed Amendments to the State Implementation Plan for Air Pollution Control relating to the Reduction of Regional Haze

Dear Mr. O'Clair:

Basin Electric Power Cooperative (Basin Electric) appreciates this opportunity to offer comments on the proposed Amendments to the State Implementation Plan for Air Pollution Control relating to the Reduction of Regional Haze. Basin Electric agrees, in general, with your individual BART Determination for our two generating units at the Leland Olds Facility. We also support the Department's determination of technical infeasibility relating to High-Dust Selective Catalytic Reduction (SCR) as applied to cyclone boilers combusting North Dakota Lignite.

We do, however, believe that the Department is in error in its applicability determination that Low-Dust and TE SCRs are technically feasible for reduction of Nitrogen oxides (NOx) from a cyclone boiler firing North Dakota Lignite. The determination was seemingly based on transference of historical operating data of biomass fired boilers whose boiler type, size, and flue gas properties do not represent a similar enough application to justify its extension to North Dakota Lignite-fired cyclone boilers. Most concerning was a reliance on vendor statements alleging their willingness to consider offering guarantees of NOx reduction performance outside the framework of binding contractual obligations to back up these statements, or evidence that these promises of potential guarantees had any guaranteed performance levels that would make them meaningful. This sets a dangerous precedent of vendor puffing serving as a basis for claiming commercial availability. The clear path forward was to do the needed pilot testing, and then base the determination on this actual performance testing in future phases of the regional haze program. EPA guidance is clear that when pilot testing is needed, the application is not commercially available. When this bright-line test is ignored, where the line is drawn becomes arbitrary and unsupportable. When a decision has hundreds of millions of dollars of potential impacts on electrical customers throughout the Midwest, the evidence supporting commercial availability needs to be placed on a firmer technical, legal and factual foundation. Although we agree with your determination that Low-Dust and TE SCRs are not economically feasible, we ask you to re-consider your determination that Low-Dust and TE SCRs are commercially available for high-sodium-lignite cyclone boilers.

Sargent and Lundy (S&L) is an independent engineering and construction management service organization who has been a leader in the design, construction, and operation of selective catalytic reduction within the energy industry. Furthermore, S&L has participated in the development of the only two tail-end configured SCRs on coal-fired boilers in the United States. S&L provided significant input as to what is known and what is unknown from their previous experience of SCR design on Texas Lignite, Sub-bituminous, and Bituminous fired boilers. S&L presented extensive evidence showing that pilot testing is required to design Low and Tail-end SCR systems for several reasons, including that the chemical and physical properties of the flue gas from combusting North Dakota Lignite in a cyclone boiler is unique and not well enough understood—based on S&L's previous experiences of SCR applications—to make it a commercially available technology.

The cost of this pilot testing is estimated to be $1.5 to 2.0 million and would take 18 to 24 months to complete. This need for pilot testing provides, under EPA guidance, the bright-line test that demonstrates that Low-Dust and Tail-end configured SCR are not a commercially available technology for high-sodium-lignite burning cyclone boilers. We are disappointed that EPA continues to encourage you to ignore EPA's own bright-line test; Low-Dust and TE SCRs require pilot testing before they can be applied to high-sodium-lignite-burning cyclones, which precludes a determination that those applications are commercially available under any reasonable interpretation of EPA's own guidance.

The NDDH requested that Basin Electric prepare a cost effectiveness determination for a Tail-End SCR application. As explained previously, it is impractical to provide a definitive cost determination for a Tail End SCR application without completing the additional testing described above. In May 2009, at the NDDH's request, a hypothetical cost effectiveness determination as developed by S&L and submitted to the Department. Hypothetical cost effectiveness were developed under five various scenarios of various catalyst life, and other input costs, i.e. natural gas, ammonia and subsequent sorbent control. The hypothetical cost effectiveness ranged from a low of $4,170 per ton up to $5,976 per ton.

The hypothetical cost effectiveness determination as determined by S&L should then be compared to the NOx control and cost impact data published by EPA as part of the Regional Haze Rule rulemaking process, including EPA's "Technical Support Document – Methodology for Developing BART NOx Presumptive Limits" (EPA Clean Markets Division, June 15, 2005). This review would indicate that EPA established the presumptive BART limits under the Regional Haze Rule of $1,350 per ton as being cost effective for all boilers other than cyclones while control technologies that had a cost impact greater than $1,350 were not cost effective. SCR were determined to be cost effective on Cyclone Boilers. The average cost effectiveness of SCR on Cyclone Boilers was determined to be $901per ton.

Attached for your consideration is S&L's report of this regulatory evaluation. The estimated cost effectiveness of $4,170 to $5,976 per ton for Tail End SCR on a cyclone boiler is significantly higher than EPA established reasonable cost threshold for NOx Controls under BART of $1,350 per ton.

Basin Electric also suggests that the Department revise what is defined as the natural background visibility and then re-setting the glide path for reasonable progress. Emission sources that are beyond the control of the Department (international point sources and particulate matter such as windblown dust and wildfires) should be removed from the reasonable progress determination. Multiple significant modeling efforts have been completed for North Dakota Class I areas that indicate the significant role the international source and the non-point source particulate matter. The conclusion that with the elimination of every in-state emissions would still not achieve the 2018 reasonable progress goal is counterintuitive and is misleading on several fronts. This discussion (Jan 2010) was submitted collaboratively to the Department under separate cover by Great River Energy, Minnkota Power Cooperative and Basin Electric Power Cooperative.

Basin Electric has now completed most of the construction of its new sulfur dioxide scrubber for its Leland Olds station several years before when construction would have commenced if Basin Electric had waited for the NDDH's BART determination. A couple months ago, the NDDH asked if Basin Electric would consider offering further early action under Reasonable Progress for non-BART-eligible sources in North Dakota. This request came too late for Basin Electric to advance it to its management and board. This does not preclude consideration of this possibility at some point in the future.

Sincerely,

Cris Miller

Cris Miller
Senior Environmental Project Administrator

/gmj
Enclosure: Sargent and Lundy Letter to Mr. Cris Miller (January 2010)

Sargent & Lundy LLC

William DePriest
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312-269-6678
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January 6, 2010

Mr. Cris Miller
Senior Environmental Project Administrator
Basin Electric Power Cooperative
1717 E. Interstate Avenue
Bismarck, ND 58503-0564

Project: Basin Electric Power Cooperative – Leland Olds Station
Subject: BART Cost Effectiveness Thresholds

Dear Mr. Miller:

The purpose of this letter report is to present the U.S. Environmental Projection Agency's (EPA's) determination of cost-effectiveness thresholds for retrofit emission control technologies under the Regional Haze Rule.[1] Basin Electric Power Cooperative asked Sargent & Lundy (S&L) to perform this evaluation to supplement the Best Available Retrofit Technology Determination prepared for Leland Olds Station Units 1 and 2, and submitted to the North Dakota Department of Health (NDDH) in August 2006.

S&L provides comprehensive consulting, engineering, design, and analysis for electric power generation and power delivery projects throughout the U.S., and we are very familiar with all of the major environmental rules regulating emissions from electric generating units, including the Regional Haze Rule. We are experienced with all aspects of air pollution control, and have prepared a number of control technology evaluations, cost-estimates, and cost-effectiveness evaluations for electric generating units. To complete this analysis, we reviewed nitrogen oxide (NOx) control and cost impact data published by EPA as part of the Regional Haze Rule rulemaking process, including EPA's "Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet" and "Technical Support Document – Methodology for Developing BART NOx Presumptive Limits" (EPA Clean Air Markets Division, June 15, 2005).

[1] The Regional Haze Rule was published on July 6, 2005, "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations," 70 FR 39104. Unless otherwise noted, all references to EPA's Regional Haze Rule in this document mean the preamble and rule published on July 6, 2005.

Sargent & Lundy LLC

Based on our review of the cost impact evaluation prepared by EPA to establish the presumptive BART limits under the Regional Haze Rule, it can be concluded that a threshold of $1,350/ton should be used to establish the cost-effectiveness of NOx retrofit controls. In general, EPA concluded that NOx control technologies that had a cost impact of less than $1,350/ton were cost-effective (e.g., combustion controls on all boiler types other than cyclones), while control technologies that had a cost impact greater than $1,350 were not cost-effective (e.g., SCR on all boiler types other than cyclones).

Background

Basin Electric Power Cooperative's (BEPC's) Leland Olds Station (LOS) Unit 2 is a B&W cyclone-fired unit with a turbine-generator nameplate rating of 440 MW. The unit was identified by NDDH as a BART-eligible source under the Regional Haze Rule. As such, BEPC is required to control emissions from LOS Unit 2 using Best Available Retrofit Technology (or "BART"). In August 2006, BEPC submitted its BART evaluation for the Leland Olds Station, including an evaluation of NOx emission controls on LOS Unit 2 (the "BART Determination Study"). The BART Determination Study concluded that selective non-catalytic reduction (SNCR) with advanced separated overfire air (ASOFA) represented BART for NOx control on LOS Unit 2, and proposed a BART NOx emission limit of 0.35 lb/mmBtu (30-day rolling average).

Tail-end selective catalytic reduction (TE-SCR) was identified in the BART Determination Study as a potentially available post-combustion NOx retrofit control technology for LOS Unit 2. However, the study determined that TE-SCR would be susceptible to unacceptable catalyst deactivation from soluble alkalis in the unit's lignite fuel (most notably sodium). The study concluded that TE-SCR was not a technically feasible NOx retrofit control technology due to the flue gas characteristics associated with the North Dakota lignite fired in LOS Unit 2.

Subsequently, NDDE requested additional analysis of the cost effectiveness of the TE-SCR technology assuming the technology was determined to be technically feasible and commercially available. In response to the Department's request, BEPC submitted a cost effectiveness evaluation of the TE-SCR on LOS Unit 2. That evaluation, dated May 27, 2009, calculated a cost effectiveness for TE-SCR (assuming technical feasibility) to be in the range of $4,170 and $5,976/ton depending on the rate of catalyst degredation and the cost of consumables (ammonia and natural gas). This letter report reviews the economic impact evaluation prepared by EPA to support the final Regional Haze Rule, which established a cost-effectiveness threshold for retrofit controls technologies.

BART Cost Effectiveness

The Regional Haze Rule requires that a determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable, taking into consideration: (1) the technology available; (2) the costs of compliance; (3) the energy and non-air-quality environmental impacts of compliance; (4) any pollution control equipment in use at the source; (5) the remaining useful life of the source; and (6) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[2] BART is determined on a case-by-case basis. Guidelines for making BART determinations are included in Appendix Y of 40 CFR Part 51 (Guidelines for BART Determinations Under the Regional Haze Rule). The Appendix Y guidelines for BART determinations identify the following five steps in a case-by-case BART analysis:

Step 1. Identify All Available Retrofit Control Technologies.
Step 2. Eliminate Technically Infeasible Options.
Step 3. Evaluate Control Effectiveness of Remaining Control Technologies.
Step 4. Evaluate Impacts and Document the Results.
Step 5. Evaluate Visibility Impacts.

Step 4 of the BART determination process involves an evaluation of potential impacts associated with the technically feasible retrofit technologies. Impact evaluations should be conducted to assess: (1) costs of compliance; (2) energy impacts; and (3) non-air quality environmental impacts. The economic analysis performed in Step 4 of the BART determination examines the cost-effectiveness of each control technology, on a dollar-per-ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from baseline emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding annual operating and maintenance (O&M) costs to the annualized capital cost of an option. Cost effectiveness of an option is simply the annual cost ($/yr) divided by the annual pollution controlled (ton/yr).

Presumptive BART Limits

In the Regional Haze Rule EPA established presumptive BART emission limits for SO_2 and NOx for certain electric generating units (EGUs) based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls.[3] The presumptive levels were intended to reflect "highly cost-effective technologies," while providing flexibility to States to consider source specific characteristics when evaluating BART.

[2] See, 70 FR 39105 col. 2.
[3] See, 40 CFR 51 Appendix Y Part IV, and 70 FR 39131.

Methodology for Developing BART NOx Presumptive Limits

To develop the presumptive BART NOx limits, EPA analyzed costs and emission reductions associated with the installation of various NOx control systems at BART-eligible EGUs including combustion control and post-combustion control systems. A detailed cost impact evaluation was developed using different combinations of boiler design, fuel, and control technology. Results of the NOx cost impact evaluation, including control costs and controlled NOx emission rates used in the evaluation, are presented in EPA's "Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet" ("BART Excel Spreadsheet"). The methodology used by EPA to prepare the BART Excel Spreadsheet is described in EPA's "Technical Support Document – Methodology for Developing BART NOx Presumptive Limits" (EPA Clean Air Markets Division, June 15, 2005).

The cost-effectiveness of each retrofit technology was calculated based on: (1) capital cost ($/kW); (2) fixed O&M ($/kW); (3) variable O&M (mills/kW-hr); and (4) controlled NOx emissions (lb/mmBtu). Capital and fixed O&M costs were adjusted based on boiler capacity to account for economies-of-scale achievable with larger units. Variable O&M costs were calculated using each individual units' baseline heat input to account for individual capacity factors. Costs were developed for bituminous, lignite and subbituminous-fired units for the following five boiler configurations: (1) Cyclones; (2) Cell Burners; (3) Dry-Bottom (DB) Wall-Fired; (4) DB Turbo-Fired; and (5) Tangentially (T) Fired units.[4]

Three coal-fired control cases were used by EPA to evaluate the cost-effectiveness of combustion and post-combustion NOx control technologies on coal-fired EGUs. A description of the three control cases, designated as Cases 1a, 1d, and 1e, is provided in Table 1.

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[4] EPA also prepared cost effectiveness calculations Stoker, Wet-Bottom, and "Other" boiler configurations; however, because of the limited number of boilers in each of those groups (5, 6, and 1, respectively) those boilers have not been included in this summary.

Table 1
BART Cost-Effectiveness Evaluation
Coal-Fired EGU Control Cases

Control Case	Control Action Taken	Major Assumptions/Notes
1a	Installation of current NOx combustion controls for unit with no prior controls, or which had controls installed before 1997. For unit with controls installed in or after 1997, install incremental controls if a complete set of combustion controls was not installed (low NOx Burners and Overfire Air). For Cyclone units, apply coal reburn if no prior controls installed. For Cell Burners, install current combustion controls if the unit had no controls or controls were installed before 1997. Do not include existing SCR or SNCR units in the Control Case NOx Rate.	If the 2004 NOx rate was less than the floor rate established for each NOx control technology, no controls added.
1d	Install SCR, unless unit already has SCR installed or the 2004 NOx rate is already at or below the SCR floor rate.	Used average heat input from 2002 – 2004 to calculate an Average NOx Rate.
1e	Install rotating overfire air (ROFA) unless unit already has SCR or the 2004 NOx Rate is already at or below the ROFA floor rate, or the calculated ROFA rate is greater than or equal to the 2004 NOx rate. Also, for Cyclone boilers install SCR. Do not include units with existing SCR/SNCR in the Control Case NOx rate.	Assumed 10,000 Btu/kWh heat rate for coal-fired boilers.

Presumptive NOx BART Limits

For all types of boilers, other than cyclone units and units already equipped with post-combustion controls (i.e., SCR and SNCR), the NOx presumptive BART limits were based on the use of current combustion control technologies. EPA established the presumptive BART levels for each subcategory based on control strategies determined to be generally cost-effective for all units within the subcategory.[5] For sources without post-combustion controls EPA established a presumption as to the appropriate BART limits based on boiler design, coal type, and combustion controls. The BART NOx presumptive emission limits are summarized in Table 2.

[5] See, 70 FR 39134 col. 2.

Table 2
Presumptive NOx Emission Limits for BART-Eligible Coal-Fired Units*

Unit Type	Coal Type	Presumptive NOx Limit
Dry-Bottom Wall-Fired	Bituminous Subbituminous Lignite	0.39 0.23 0.29
Tangential Fired	Bituminous Subbituminous Lignite	0.28 0.15 0.17
Cell Burners	Bituminous Subbituminous	0.40 0.45
Dry-Turbo-Fired	Bituminous Subbituminous	0.32 0.23
Wet-Bottom Tangential-Fired	Bituminous	0.62
Cyclone Boilers	All	0.10

* 70 FR 39135 Table 2.

Presumptive BART Cost-Effectiveness

EPA developed the presumptive NOx BART limits listed in Table 2 based on an evaluation of the cost-effectiveness of each control technology. A summary of the average cost-effectiveness for each control case (calculated as the total control cost for all units within the subcategory divided by the total annual tons of NOx removed) by boiler type is provided in Table 3.

Table 3
Average Cost Effectiveness of NOx Controls for BART-Eligible Coal-Fired Units by Boiler Type[6]

Boiler Type	Unit Average Cost Per Ton Removed		
	Case 1a	Case 1d	Case 1e
Cyclone – All	$1,330	$901	$901
Cell Burner – All	$1,198	$1,383	$722
DB Wall Fired-All	$723	$1,554	$853
DB Turbo Fired – All	$622	$1,483	$733
T-Fired – All	$376	$2,012	$875

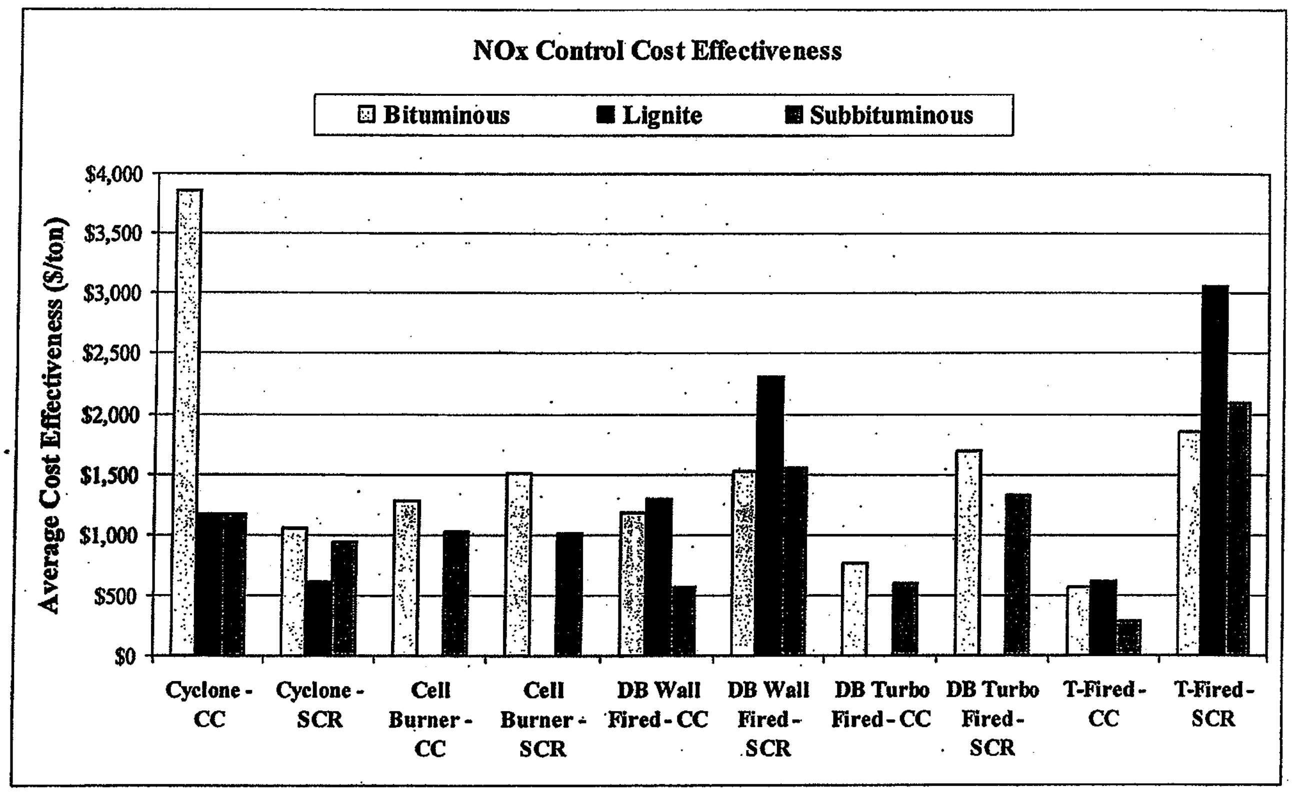
Case 1a = current combustion controls (LNB+OFA for all boiler types) and coal reburn on cyclone boilers.
Case 1d = SCR on all units.
Case 1e = advanced combustion controls (ROFA on all boiler types) and SCR on cyclones.

[6] See, 70 FR 39135,Table 3. For EGUs currently using post-combustion controls such as SCR or SNCR to reduce NOx during part of the year, EPA established a presumption that use of these same controls year-round is BART. EPA's cost impact assessment showed year-round operation of existing SCRs, compared to operation during the 5-month ozone season only, to be highly cost effective with an average cost-effectiveness of $170/ton (70 FR 39134).

For all the boiler types (except cyclones) the NOx BART limits were based on the use of current combustion control technologies. EPA's cost impact analysis found that combustion controls (Case 1a) were generally, but not always, more cost-effective than post-combustion controls such as SCRs (Case 1d). The cost-effectiveness of combustion control systems (for boiler types other than cyclones) averaged between $376/ton (T-Fired Units) and $1,198/ton (Cell Burners). Combustion controls on Cyclone Boilers (i.e., coal reburn) were determined to be less cost-effective, averaging $1,330/ton removed.

SCR control systems were found to be less cost-effective on all boiler types except Cyclone Boilers. The cost-effectiveness of SCR for all boiler types other than cyclones averaged between $1,383/ton (Cell Burners) and $2,012/ton (T-Fired units). The cost-effectiveness of SCR control on Cyclone Boilers was determined to average $901/ton. The average cost effectiveness of combustion controls and SCR for each boiler type and fuel (i.e., bituminous, lignite, and subbituminous) are shown in Figure 1.

Figure 1
Average Cost Effectiveness of NOx Combustion Controls and SCR



Based on the cost impact results summarized in Figure 1 EPA concluded that combustion controls could cost-effectively reduce NOx emissions on all boiler types other than cyclones, while post-combustion controls, including SCR, were excluded from EPA's presumptive BART determination based on cost impacts.

Cyclone Cost Evaluation

EPA's cost impact evaluation concluded that SCR was more cost-effective than combustion controls on Cyclone Boilers. SCR was determined to be more cost-effective on Cyclone Boilers for several reasons, including: (1) relatively high baseline NOx emission rates; (2) relatively low combustion control efficiencies; (3) high SCR control efficiencies; (4) high combustion control capital costs (compared to combustion controls on other boiler types); and (5) high combustion control O&M costs. Some of the control and cost assumptions used by EPA to develop the BART NOx presumptive limits are summarized in Tables 4 and 5.

Table 4
BART NOx Control Assumptions - Summary

NOx Rate or Control Efficiency	Unit	Boiler Type				
		Cyclone	Cell Burner	DB Wall-Fired	DB Turbo-Fired	T-Fired
Baseline 2004 NOx Rate (units w/o combustion controls)	lb/mmBtu	0.79	0.47	0.40	0.41	0.34
Baseline 2004 NOx Rate (all units)	lb/mmBtu	0.68	0.40	0.37	0.39	0.29
Controlled NOx Rate (combustion controls)	lb/mmBtu	0.47	0.37	0.27	0.22	0.19
Average Combustion Control Efficiency*	%	40.5%	21.2%	32.5%	46.3%	44.1%
Controlled NOx Rate (SCR)	lb/mmBtu	0.073	0.060	0.060	0.060	0.060
Average SCR Control Efficiency**	%	**89.3%**	**85.0%**	**83.8%**	**84.6%**	**79.%**

* Average combustion control efficiency was calculated based on the 2004 baseline NOx emission rate associated with units without current combustion controls.

** Average SCR control efficiency was calculated based on the 2004 Baseline NOx emission rate for all units not currently equipped with SCR control.

Table 5
BART Cost Assumptions - Summary

Control Technology	Cost	Unit	Boiler Type				
			Cyclone	Cell Burner	DB Wall-Fired	DB Turbo-Fired	T-Fired
Combustion Controls	Capital Costs	$/kW	$72.66	$23.43	$23.43	$23.43	$14.52
	Fixed O&M	$/kW	$1.10	$0.35	$0.36	$0.36	$0.22
	Variable O&M	mill/kWh	0.26	0.07	0.07	0.07	0.02
	Total Cost	mill/kWh	1.80	0.50	0.47	0.50	0.27
SCR	Capital Costs	$/kW	$100	$100	$100	$100	$100
	Fixed O&M	$/kW	$0.66	$0.66	$0.66	$0.66	$0.66
	Variable O&M	mill/kWh	0.60	0.60	0.60	0.60	0.60
	Total Cost	mill/kWh	2.66	2.41	2.25	2.25	2.18

Based on a review of the control and cost assumptions summarized in Tables 4 and 5, it appears that the most significant variable contributing to the cost effectiveness of SCR on Cyclone Boilers is the relatively high cost of combustion controls. Combustion controls were significantly more expensive on Cyclone Boilers than on other boiler types. Capital costs for combustion controls (i.e., coal reburn) on cyclones averaged $72.66/kW compared to capital costs of $23.43/kW for combustion controls on Cell Burners, DB Wall-Fired, and DB Turbo-Fired units, and $14.52/kW on T-Fired units. Similarly, both fixed and variable O&M costs were significantly higher for Cyclone Boiler combustion controls. As a result, total annual costs for combustion controls on Cyclone Boilers averaged 1.80 mill/kWh, compared to 0.50 mill/kWh for Cell Burners and DB Turbo-Fired units, 0.47 mill/kWh for DB Wall-Fired units and only 0.27 mill/kWh for T-Fired units.

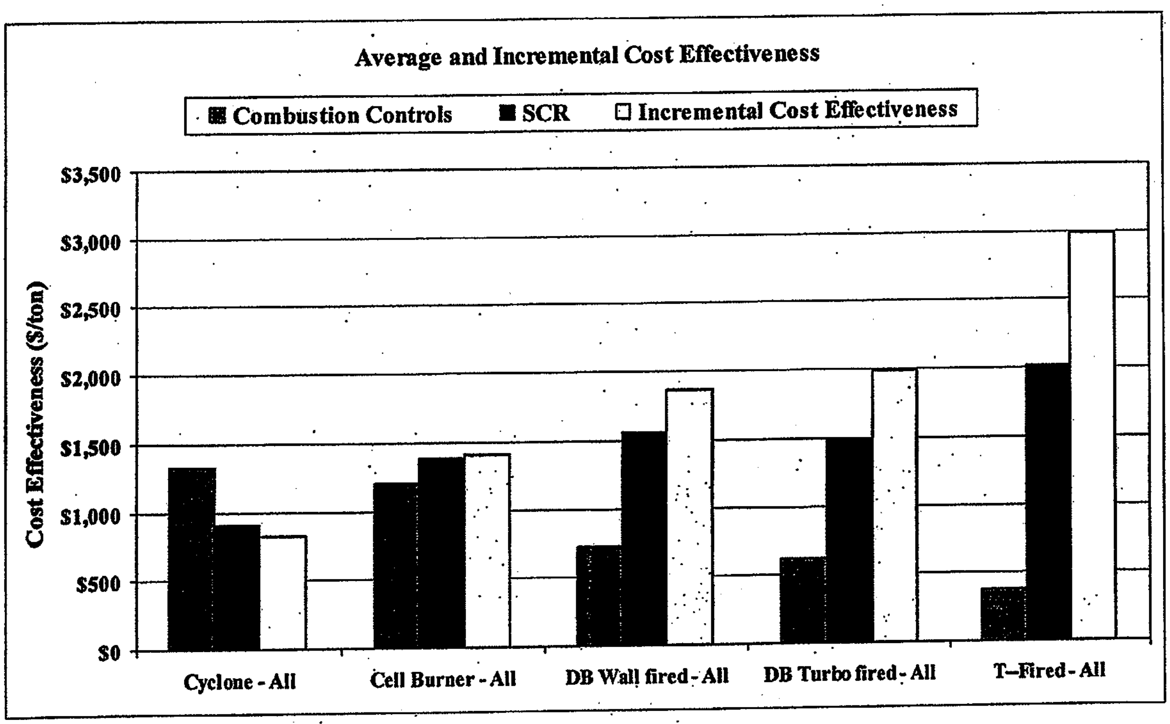
On the other hand, the same cost assumptions were used for SCR retrofit controls regardless of boiler type (i.e., $100/kW Capital Costs-adjusted for boiler size, $0.66/kW Fixed O&M, and 0.60 mill/kWh Variable O&M). Overall annual costs of an SCR system were similar for all boiler types, averaging between 2.18 mill/kWh (T-Fired units) and 2.66 mill/kWh (Cyclone Boilers).

Due to the relatively low control effectiveness and the high cost of combustion controls (including both capital and O&M), combustion controls were determined to be less cost effective on Cyclone Boilers than SCR. SCR control was assumed to achieve significantly lower controlled NOx emissions (0.073 lb/mmBtu compared to 0.47 lb/mmBtu with combustion controls) at a relatively low incremental increase in capital costs ($100/kW compared to $72.66/kW for combustion controls). Based on these assumptions SCR was found to be more cost effective on Cyclone Boilers than combustion controls.

BART Cost Effectiveness Conclusions

Regardless of the assumptions used in the BART cost impact evaluation, EPA concluded that post-combustion controls were not cost effective for all boiler types other than Cyclone Boilers. Thus, the cost effectiveness of SCR controls on those boiler types can be used to determine the cost-effectiveness threshold used by EPA to conclude that post-combustion controls were not cost-effective. In addition to the average cost effectiveness of a control technology (i.e., relative to the base case), the incremental cost-effectiveness to go from one level of control to the next more stringent level of control (i.e., from combustion controls to SCR) may be used to evaluate the cost impact of the more stringent control. Figure 2 summarizes the average cost effectiveness of combustion controls, the average cost effectiveness of SCR, and the incremental cost effectiveness of SCR (compared to combustion controls) for each boiler type

Figure 2
Average and Incremental Cost Effectiveness of NOx Retrofit Controls

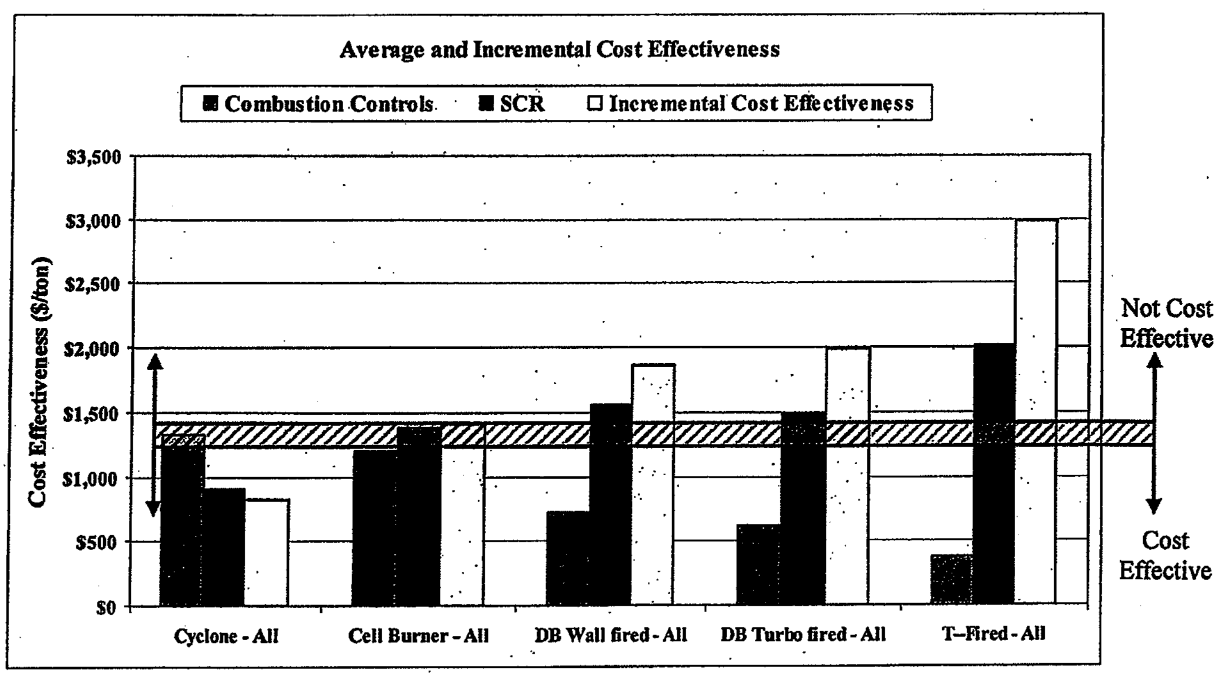


For all boiler types other than cyclones, combustion controls were determined to be a cost-effective NOx retrofit control option while post-combustion SCR was not considered to be cost-effective. Combustion controls had an overall average cost effectiveness (calculated by dividing total annual costs by total annual tons of NOx removed for all boiler categories other than cyclones) of approximately $535/ton, and ranged from $281/ton (T-Fired subbituminous units) to $1,296/ton (DW Wall-Fired lignite units). SCR had an overall average cost effectiveness of $1,749/ton, ranging from $1,016/ton (Cell Burner – subbituminous) to $3,060/ton (T-Fired lignite units). Other than Cyclone Boilers, the Cell Burner category had the highest combustion control cost-effectiveness and the lowest SCR cost-effectiveness at $1,198/ton and $1,383/ton, respectively.

Conversely, SCR, rather than combustion controls, were determined to be cost-effective on Cyclone Boilers. The average cost-effectiveness of combustion controls and SCR on Cyclone Boilers was determined to be $1,330/ton and $901/ton, respectively.

Figure 3 shows the average and incremental cost-effectiveness for combustion controls and SCR on each boiler type, and shows the approximate thresholds used by EPA to establish cost-effectiveness.

Figure 3
Average and Incremental Cost Effectiveness of NOx Retrofit Controls
Showing Cost-Effectiveness Thresholds



Based on the cost impact evaluation prepared by EPA to establish the presumptive BART limits, it can be concluded that a threshold of $1,350/ton should be used to establish the cost-effectiveness of NOx retrofit control technologies. In general, control technologies that had a cost impact of less than $1,350/ton were determined to be cost-effective (e.g., combustion controls on all boiler types other than cyclones), while control technologies that had a cost impact greater than $1,350 were determined not to be cost-effective (e.g., SCR on all boiler types other than cyclones).[7]

Again, the purpose of this letter report is to summarize EPA's determination of cost-effectiveness thresholds for retrofit emission control technologies under the Regional Haze Rule. This evaluation of EPA's cost-effectiveness threshold for retrofit emission control technologies was based on a review of EPA documents published to support the Regional Haze Rule, and should be directly applicable to cost-effectiveness evaluations included in the Leland Olds BART Determination Study.

Should you need additional information, please do not hesitate to contact me.

Very Truly Yours,

Wm. DePriest

William DePriest
Sr. Vice President and
Director Environmental Services

[7] EPA's cost impact evaluation included a couple of notable exceptions to this general statement. For example, combustion controls on both lignite- and subbituminous-fired Cyclone Boilers had a cost-effectiveness of $1,161/ton and $1,167/ton (which is below the $1,350/ton threshold). Similarly, post-combustion SCR on subbituminous-fired Cell Burners had a cost impact of $1,016/ton (which is below the $1,350/ton threshold).

January 7, 2010

North Dakota Department of Health
Attn: Terry O'Clair
Second Floor
918 East Divide Avenue
Bismarck, ND
58501-1947

Re: Comments on Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to Reduction of Regional Haze

Please accept the attached document that was developed by Bob Paine, from AECOM, on behalf of the undersigned Electric Cooperatives. Mr. Paine presents valid arguments for re-visiting natural background conditions and re-setting the glide path. He recommends additional modeling to exclude uncontrollable particulate matter (PM) emissions, such as windblown dust and wildfires, as well as international SO2 and NOx emissions, which are not within the jurisdiction of the North Dakota Department of Health. The North Dakota Department of Health should also consider Mr. Paine's recommendations as part of their weight of evidence for determining reasonable progress under the Regional Haze Requirements.

//s//Lyle Wytham
Manager, Environmental Services
BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

//s//Mary Jo Roth
Manager, Environmental Services
GREAT RIVER ENERGY®
A Touchstone Energy® Cooperative

//s// John Graves,
Environmental Manager
Minnkota Power Cooperative, Inc.

Enc: "Visibility Projections at North Dakota Class 1 Areas with Consideration of Uncontrollable Emissions" dated January 6, 2010

Visibility Projections at North Dakota Class I Areas with Consideration of Uncontrollable Emissions

(Comments provided for revisions to the North Dakota State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze)

Robert Paine, AECOM Environment
January 6, 2010

Introduction

The purpose of this document is to comment on the use of the default natural visibility conditions defined by the United States Environmental Protection Agency (USEPA)[1] to assess progress in attaining the goals of the Regional Haze Rule (RHR), which is the subject of the North Dakota State Implementation Plan (SIP). In its December 2, 2009 draft SIP, North Dakota notes in Section 8.6.3.3 that,

> "Achieving natural conditions will require the elimination of all anthropogenic sources of emissions. Given current technology, achieving natural conditions is an impossibility. Any estimate of the number of years necessary to achieve natural visibility conditions would require assumptions about future energy sources, technology improvements for sources of emissions, and every facet of human behavior that causes visibility impairing emissions. The elimination of all SO_2 and NO_x emissions in North Dakota will not achieve the uniform rate of progress for this [2018], or any future planning period. Any estimate of the number of years to achieve natural conditions is questionable because of the influence of out-of-state sources."

It is clear that the use of USEPA default natural conditions leads to unworkable and absurd results for North Dakota's ability to determine the rate of progress toward an unattainable goal. The definition of natural conditions that can be reasonably attained for a reasonable application of USEPA's Regional Haze Rule must be revised. USEPA provides each state with ability to do this, and North Dakota should seriously consider this option.

The objective of this memorandum is to summarize recent modeling studies of natural visibility conditions and to suggest how such studies can be used in evaluating the uniform rate of progress in reducing haze to attain natural visibility levels. In addition, the distinction between natural visibility and policy relevant background visibility is discussed. Treatment of this issue by other states who are also considering what to do for their Regional Haze Rule SIPS is also discussed.

[1] USEPA, 2003. *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule.* EPA-454/B03-005. http://www.epa.gov/ttn/oarpg/t1/memoranda/rh_envcurhr_gd.pdf.

Natural Haze Levels

The Regional Haze Rule establishes the goal that natural visibility conditions should be attained in Federal Class I areas by the year 2064. Additionally, the states are required to determine the uniform rate of progress (URP) of visibility improvement necessary to attain the natural visibility goal by 2064. Finally, each state must develop a SIP identifying reasonable control measures that will be adopted well before 2018 to reduce source emissions of visibility-impairing particulate matter (PM) and its precursors (SO_2 and NO_x).

Estimates of natural haze levels have been developed by the USEPA for visibility planning purposes and are described in the above-referenced USEPA 2003 document. The natural haze estimates were based on ambient data analysis of selected PM species for days with good visibility and are shown in Table 1. These estimates were derived from Trijonis (1990)[2] and use two different sets of natural concentrations for the eastern and western U.S. Tombach (2008)[3] provides a detailed review and discussion of uncertainty in the USEPA natural PM estimates. Natural visibility can be calculated using the IMPROVE equation which calculates the light scattering caused by each component of PM. Objections have been raised both in the assumed natural concentrations of PM and in the method by which the IMPROVE equation is used to calculate visibility (EPRI, 2004). In response, changes in the IMPROVE equation and in the method for calculating natural visibility were developed in 2005 and are described by Pitchford et al.[4]

The USEPA guidance also makes provision for refined estimates of site-specific natural haze that differ from the default values using either data analysis or model simulations. However, most states have continued to use the default natural haze levels for calculating the progress toward natural visibility conditions. Tombach and Brewer (2005)[5] reviewed natural sources of PM and identified several Class I areas for which evidence supports adjustments to the natural levels. Tombach (2008) also reviewed estimates of natural haze levels and proposed that, instead of using two sets of default natural PM concentrations for the eastern and western US, a large number of sensitivity zones should be developed that reflect regional variability in natural PM sources. Tombach (2008) also suggested that modeling studies are a possible approach to further revise estimates of natural PM concentrations.

Previous modeling studies have shown that the estimates of natural visibility described above for "clean" days will differ from the results of model simulations when United States anthropogenic emissions are totally eliminated (Tonnesen et al., 2006[6]; Koo et al., 2009[7]), especially when natural wild fire emissions are

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[2] Trijonis, J. C. Characterization of Natural Background Aerosol Concentrations. Appendix A in Acidic Deposition: State of Science and Technology. Report 24. Visibility: Existing and Historical Conditions -- Causes and Effects. J. C. Trijonis, lead author. National Acid Precipitation Assessment Program: Washington, DC, 1990.

[3] Tombach, I., (2008) *Natural Haze Levels Sensitivity -- Assessment of Refinements to Estimates of Natural Conditions,* Report to the Western Governors Association, January 2008, available at http://www.wrapair.org/forums/aamrf/projects/NCB/index.html.

[4] Pitchford, M., Malm, W., Schichtel, B., Kumar, N., Lowenthal, D., Hand, J., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, J. Air & Waste Manage, Assoc. 57: 1326 – 1336, 2007.

[5] Tombach, I., and Brewer, P. (2005). Natural Background Visibility and Regional Haze Goals in the Southeastern United States. *J. Air & Waste Manage. Assoc. 55*, 1600-1620.

[6] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside,

included in the model simulation. Because the URP is calculated using model simulations of PM on the 20% of days with the worst visibility, wild fires and other extreme events can result in modeled levels of natural haze (even without any contribution of US anthropogenic sources) that are significantly greater than the natural levels used in the USEPA guidance for URP calculation. This could make it difficult or impossible for states to identify emissions control measures sufficient to demonstrate the URP toward attaining visibility goals because the endpoint is unachievable even if all US anthropogenic emissions are eliminated, as North Dakota has already determined even for the interim goal in 2018.

Modeling studies for natural ozone and PM have been completed at the global scale with the GEOS-CHEM model (Fiore et al., 2003[8]; Park et al., 2004[9]). Park et al. (2006)[10] estimated the contribution of both natural PM and international transport of PM in the eastern and western U.S. and compared their results to the USEPA default natural concentrations. They found significantly less difference in the natural concentrations between the east and west compared to the USEPA default values. Their modeled western concentrations were greater than the USEPA default values, while their modeled eastern concentrations were lower than the default values.

Tonnesen et al. (2006)[11] performed visibility modeling simulations for the WRAP using a "clean emissions" scenario in which all (US and international) anthropogenic emissions were removed from the model, and the GEOS-CHEM natural simulation was used to provide boundary conditions for CMAQ. This CMAQ simulation was not considered an adequate representation of natural conditions because some natural emissions data were not available. However, it did include natural fire emissions and was useful for showing the maximum visibility possible when all US and international anthropogenic emissions were totally eliminated. The model results were evaluated for annual average visibility and extinction coefficient, shown in Figure 1. The largest source of natural emissions in this model simulation was from wildfires, which were predominantly located in the Western US.

Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

[7] Koo B., C.J. Chien, G. Tonnesen, G.Yarwood, J. Johnson, T. Sakulyanontvittaya, P. Piyachaturawat, and R. Morris, (2009). Revised Natural Components for Regional Modeling of Background Ozone and Particulate Matter and their Impacts on Emissions Control Strategies, manuscript under preparation.

[8] Fiore, A., D. J. Jacob, H. Liu, R. M. Yantosca, T. D. Fairlie, and Q. Li (2003) Variability in surface ozone background over the United States: Implications for air quality policy, J. Geophys. Res., 108, ACH 19-1 - ACH 19-12.

[9] Park, R. J., D. J. Jacob, B. D. Field, R. M. Yantosca, and M. Chin (2004) Natural and transboundary pollution influences on sulfate-nitrate-ammonium aerosols in the United States: Implications for policy, *J. Geo-phys Res., 109*, D15204, doi:10.1029/2003JD004473.

[10] Park, R. J., D. J. Jacob, N. Kumar, R. M. Yantosca (2006) Regional visibility statistics in the United States: Natural and transboundary pollution influences, and implications for the Regional Haze Rule, *Atmos. Env., 40*: 5405-5423.

[11] Tonnesen, G., Omary, M., Wang, Z., Jung, C.J., Morris, R., Mansell, G., Jia, Y., Wang, B., and Z. Adelman (2006) Report for the Western Regional Air Partnership Regional Modeling Center, University of California Riverside, Riverside, California, November. (http://pah.cert.ucr.edu/aqm/308/reports/final/2006/WRAP-RMC_2006_report_FINAL.pdf).

More recently, Koo et al. (2009) have completed CMAQ model simulations of natural ozone and haze levels using a more complete natural emissions inventory. The updated Koo et al. natural visibility modeling is currently the best available estimate of natural visibility for the worst 20% model days. It represents the absolute maximum visibility conditions possible in the model when all anthropogenic US and international emissions are controlled. However, those results have not yet been evaluated to identify the modeled natural concentrations for the worst 20% visibility days.

Policy Relevant Background Visibility

The use of natural haze levels is an unattainable goal for U.S. domestic planning purposes because the Regional Haze Rule does not have jurisdiction over international emissions. A more appropriate goal would be based on the background concentration resulting from a combination of natural PM and international transport of PM.

For air quality planning purposes, the USEPA has identified the policy-relevant background (PRB) ozone concentration as that which would occur in the United States in the absence of anthropogenic emissions of VOC and NO_x in continental North America (USEPA, 2007). The PRB ozone concentration represents the contribution of international transport of ozone and photochemical production from biogenic VOC and NO_x precursors within North America. The PRB is useful for ozone planning using air quality models because it defines the minimum level of ozone that can be simulated in the model when all anthropogenic emissions of VOC and NO_x are controlled 100% in North America. Similarly, PRB levels could be defined for $PM_{2.5}$ and for haze, and this would be useful for estimating the rate of progress that the states are making through the control of domestic sources of visibility impairing species.

PRB levels of haze can be evaluated in air quality model simulations by excluding all anthropogenic emissions within North America, or more appropriately, excluding all anthropogenic emissions within the US only (especially relevant for North Dakota). Such model simulations have not yet been completed; however, existing RPO data sets could be modified to perform new CMAQ simulations for use in this analysis.

The RPOs have completed modeling studies using source apportionment tools to evaluate individual sources that contribute to visibility impairment at Class I Areas. Both WRAP and CENRAP have performed CAMx simulations using the Particulate Source Apportionment Tool (PSAT) to evaluate emissions sources that contribute to sulfate and nitrate at receptor sites. Figure 2 shows the CAMx PSAT results for major contributors to sulfate for the 20% worst visibility days at the Lostwood Wilderness Area (LWA) and Theodore Roosevelt National Park (TRNP) Class I areas. The source apportionment results provide some of the same information that would be obtained from model simulations to evaluate PRB haze. For example, the contribution of boundary conditions in the CAMx PSAT results represent contributions of international transport from areas outside the model domain, although parts of in Canada and Mexico are included within the model domain and are represented explicitly in the PSAT results. Figure 2 shows that in the PSAT results, Canadian point sources of SO_2 (PT_CN) and international transport were the two largest sources of sulfate at both the LWA and TRNP Class I areas, producing approximately 1.6 ug/m^3 of sulfate of the total of 2.48 ug/m^3 at LWA, and approximately 0.93 ug/m^3 of sulfate of the total of 1.61 ug/m^3 at TRNP. For both sites, point sources of SO_2 within North Dakota were ranked below these sources as the third largest source of sulfate in the PSAT results.

While the PSAT results are useful for identifying the relative important of different source regions and emissions source categories at individual Class I Areas, there would be advantages to also performing a model simulation that included only international transport (including Canadian and Mexican emissions) and natural emissions to more accurately estimate PRB haze levels that North Dakota could then adopt as a refined natural background visibility goal for the Regional Haze Rule.

Texas and Colorado SIP Issues

There are many similarities between the Regional Haze Rule (RHR) challenges for North Dakota and Texas in that both states have significant international and natural contributions to regional haze in Class I areas in their states. The Texas Commission on Environmental Quality (TCEQ) has introduced alternative RHR glide paths to illustrate their rate of progress toward the RHR goals. Since TCEQ has already gone through the process of a RHR State Implementation Plan (SIP) development and comment period, it is instructive for the North Dakota to look at the TCEQ approach, the comments provided to TCEQ, and TCEQ's reaction to the comments.

In addition, Colorado's approach to Reasonable Further Progress prudently focuses upon source groups and particulate species for which Colorado sources contribute significantly to regional haze for the worst 20% haze days. This approach, consistent with that of Texas, concludes that some of the particulate species that contribute to regional haze are highly variable, not principally from anthropogenic sources, difficult to model, and difficult to control.

<u>Similarities Between North Dakota and Texas</u>

Similarities to be considered for the RHR SIP development in both North Dakota and Texas include the items listed below.

- Both states have Class I areas for which a considerable fraction of the regional haze is due to international transport
- Both states have Class I areas in their western portion, which results in the prevailing winds taking emissions from within their states away from those Class I areas.
- The distance to the nearest Class I areas associated with the prevailing winds is many hundreds of kilometers.
- The impact of the large haze precursor emitters in each state is noticeable when the wind directions advect their plumes toward the Class I areas, but this happens only a small fraction of the time.
- As a result, there is a substantial reduction in SO_2 and NO_x emissions from the BART-eligible sources in each state, but this reduction results in a relatively small impact on regional haze mitigation. Additional emission reductions that are advocated by some commenters would, therefore, have a minimal benefit on visibility improvement at substantial cost.
- In the RHR SIP development, both states have attempted to account for the effects of anthropogenic emissions that they can control in alternative analyses. These analysis result in a finding that the in-state emission reductions come closer to meeting the Uniform Rate of Progress glide path goals for 2018. However, due to the low probability of impact of these sources on the worst 20% days, the effectiveness of in-state emission controls on anthropogenic sources subject to controls is inherently limited.

Differences Between RHR SIP Approaches: North Dakota and Texas

Although both North Dakota and Texas have presented alternative analyses that attempt to present the effect of emissions that each state can control and discount the rest, the two states have used different approaches. The nature of these differences and a discussion of the approaches taken by each state are noted below.

- North Dakota appears to have not reduced the deciview value of the natural condition endpoint, but instead altered the beginning point. On the other hand, TCEQ appears to have altered the endpoint. It is my opinion that altering the endpoint to reflect haze components that are currently affecting visibility but which cannot be controlled by the Regional Haze Rule has its merits. The beginning point is set by observations, so it should not be altered.

- TCEQ decided that coarse and fine PM measured at the Class I areas were due to natural causes (especially on the worst 20% days), and adjusted the natural conditions endpoint accordingly. The Federal Land Managers (FLMs) agreed with this approach for the most part[12], but suggested that only 80% of these concentrations would be due to natural causes, and 20% would be due to anthropogenic causes. TCEQ determined from a sensitivity analysis that the difference in these two approaches was too small to warrant a re-run of their analysis, but it is important that the FLMs agreed to a state-specific modification of the natural conditions endpoint, and this substantially changed the perceived rate of progress of the SIP plan toward the altered natural conditions endpoint.

- Although the TCEQ did not address other particulate matter components in this same way, our independent analysis of the worst 20% haze days in 2002 for Class I areas in North Dakota suggest that other components, such as organic matter due to wildfires, could be substantially due to natural causes, so that this component should also be considered as at least partially natural.

- The TCEQ discussed the issue of how emissions from Mexico could interfere with progress on the RHR, but they did not appear to adjust the glide path based upon Mexican emissions. On the other hand, North Dakota did make adjustments based upon anthropogenic emissions that could be controlled, but did not take into account any specific particulate species that are generally not emitted by major anthropogenic sources of SO_2 and NO_x.

Colorado RHR Issues Consistent with Texas

Similar to Texas, Colorado[13] has determined that SO_2 and NO_x are precursors to important visibility PM species, are predominantly due to anthropogenic sources, and can be effectively controlled for stationary sources. The other four PM species that affect visibility are coarse and fine matter as well as organic and

[12] See Appendix 2-2 at http://www.tceq.state.tx.us/implementation/air/sip/bart/haze_appendices.html.

[13] Colorado has posted stakeholder presentations at http://www.cdphe.state.co.us/ap/RegionalHaze/RHFeb08reasonableprogress.pdf and http://www.cdphe.state.co.us/ap/RegionalHaze/stakepresentation02-27-08.pdf.

elemental carbon. Colorado has determined that sources of these constituents are mostly natural and difficult to quantify, model, and control. This is consistent with Texas in that the focus should be on the progress made in controlling emissions from stationary sources of SO_2 and NO_x. In North Dakota, the recommended BART reductions for SO_2 and NO_x sources go well beyond the fractional progress toward zero emissions by the first milestone year of 2018, which represents less than 25% of the time period of the RHR implementation.

Recommendations and Conclusions

I recommend that North Dakota consider alternative endpoints to the natural conditions glide path for progress on the worst 20% haze days in order to indicate a more rational analysis. The use of the natural conditions provided by the default EPA approach to the RHR results in an outcome that is counterintuitive and frustrating because it indicates that even with a total shutdown of in-state emissions, not even the 2018 goal is met.

North Dakota could accomplish this goal in one of two ways. It could, similar to what was done in Texas, identify particulate matter components that are inherently dominated by natural emission sources such as windblown dust and wildfires on the worst 20% haze days. For example, the FLMs have already agreed with Texas that 80% of the coarse and fine particulate matter for these days could be considered to be uncontrollable and due to natural causes. I recommend that organic matter be added to this list, for which well over 50% would likely be attributable to natural causes (wildfires) on the 20% worst haze days when this particulate matter component is dominant. However, this approach does not address the issue of uncontrollable international emissions.

Therefore, a better approach that I recommend[14] would be to combine the effects of the uncontrollable particulate matter components and the SO_2 and NO_x emissions from international sources to determine a new glide path endpoint that is achievable by controlling anthropogenic emissions within the USA only. To compute this new endpoint, I recommend that CMAQ modeling be conducted for the base case (already done) and then for a future endpoint case with no USA anthropogenic emissions, but with particular matter emissions associated with uncontrollable coarse matter, fine matter, and organic carbon, as well as for SO_2 and NO_x emissions associated with all non-USA sources set to the current baseline levels. Then, North Dakota could use a relative reduction factor (RRF) approach to determine the ratio of the haze impacts between the base case and the reasonable future case, and then apply the RRF values to the baseline haze to obtain a realistic "natural conditions" haze endpoint.

[14] These comments and recommendations were discussed with Gail Tonneson, who has provided helpful input and review for this document.

Table 1: Average Natural Levels of Aerosol Components from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003)

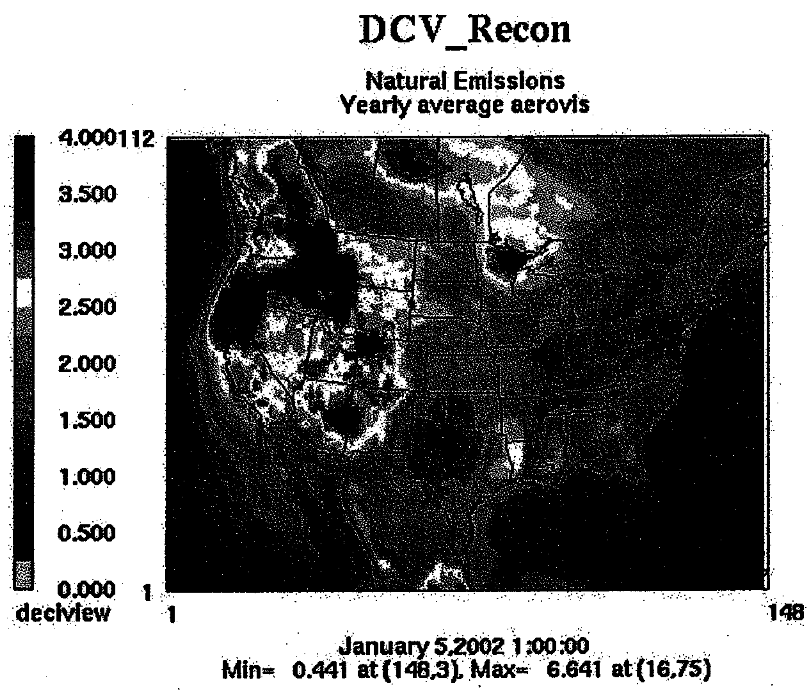
	Average Natural Concentration		Error Factor	Dry Extinction Efficiency (m^2/g)
	West ($\mu g/m^3$)	East ($\mu g/m^3$)		
Ammonium sulfate [b]	0.12	0.23	2	3
Ammonium nitrate	0.10	0.10	2	3
Organic carbon mass [c]	0.47	1.40	2	4
Elemental carbon	0.02	0.02	2-3	10
Soil	0.50	0.50	1½ - 2	1
Coarse Mass	3.0	3.0	1½ - 2	0.6

a: After Trijonis, see footnote 12

b: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.1 $\mu g/m^3$ and 0.2 $\mu g/m^3$ of ammonium bisulfate.

c: Values adjusted to represent chemical species in current IMPROVE light extinction algorithm; Trijonis estimates were 0.5 $\mu g/m^3$ and 1.5 $\mu g/m^3$ of organic compounds.

Figure 1: WRAP Clean Model Simulation Annual Average for Visibility (top) and Extinction Coefficient (bottom) from Tennessee et al. (2006)



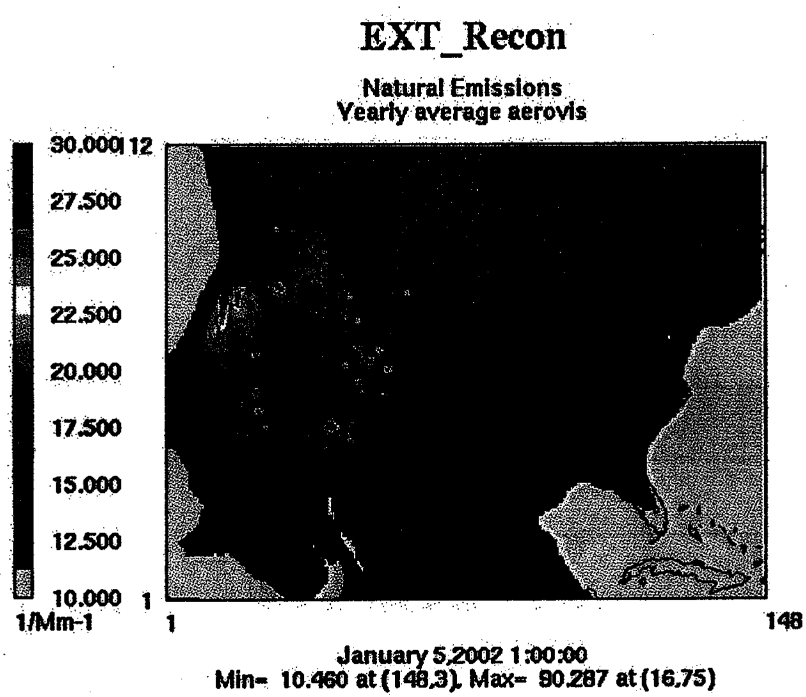
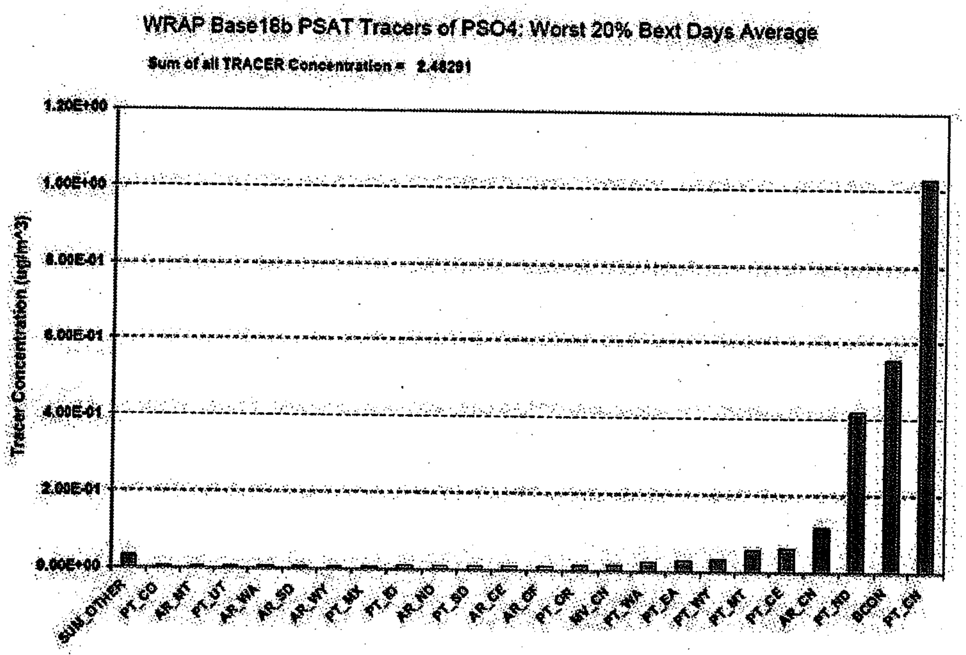
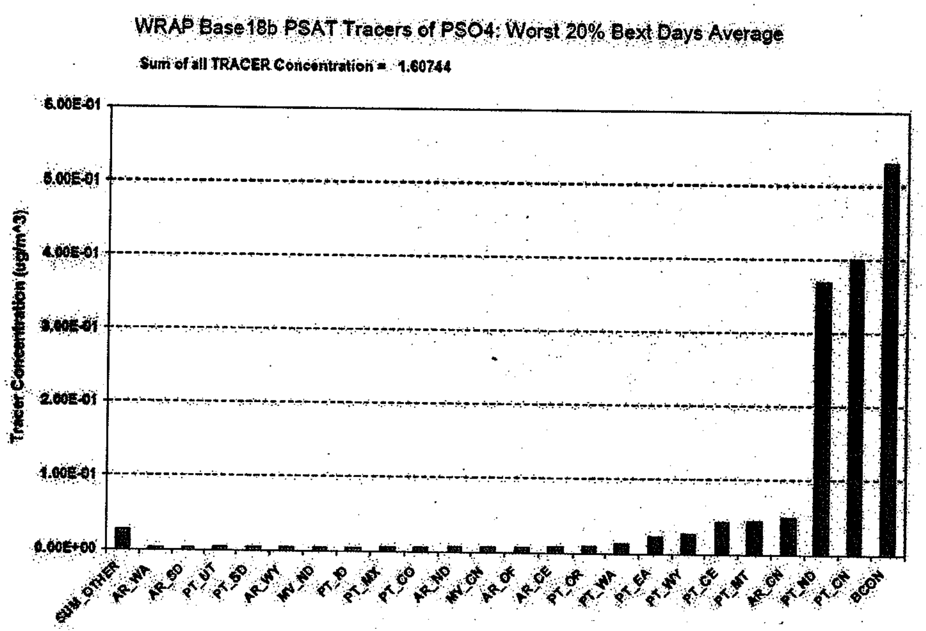


Figure 2: CAMx Source Apportionment Results for Major Contributors to Sulfate for the 20% Worst Visibility Days at Lostwood (top) and TNRP (bottom) Class I Areas

Lostwood,ND (LOST1)



Theodore Roosevelt,ND (THRO1)



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January 7, 2010

North Dakota Department of Health
Attn: Terry O'Clair
Second Floor
918 East Divide Avenue
Bismarck, ND
58501-1947

Re: Comments on Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to Reduction of Regional Haze

Great River Energy is a generation and transmission electric cooperative based in Maple Grove, Minnesota. Our two coal-fired power plants are located in North Dakota: Coal Creek Station, a 1,129-megawatt plant located near Underwood; and Stanton Station, a 190-megawatt plant located near Stanton. Great River Energy respectfully provides the following general comments to North Dakota's Regional Haze State Implementation Plan ("SIP").

Since 2005, Great River Energy has been working with the North Dakota Department of Health ("NDDH") to define Best Available Retrofit Technologies ("BART") for three of our coal-fired units in North Dakota. Both Coal Creek Units 1 and 2, as well as Stanton Station Unit 1, are BART affected sources due to their dates of construction and their modeled contributions to visibility impairment in North Dakota Class 1 areas, Lostwood Wilderness Area and Theodore Roosevelt National Park's North, South and Elkhorn Units.

Great River Energy originally submitted detailed BART analyses for our affected units, Stanton and Coal Creek stations, in June and August, respectively, of 2006. Each BART submittal was amended several times in response to Environmental Protection Agency ("EPA"), Federal Land Manager and NDDH comments. Stanton's final BART submittal was provided in January 2008 and Coal Creek's in December 2007. These documents were the foundations for the NDDH BART determinations, and draft Title V permits-to-construct, which were issued in May of 2008, and act as reference materials in the NDDH Regional Haze Rule SIP.

NDDH technical modeling appropriately utilizes the most up-to-date modeling science as grounded by actual monitored data to ensure relative accuracy.

Great River Energy supports using the best and most current science as part of regulatory decision making. Specifically, Great River Energy strongly believes that "models" must be calibrated to actual monitored data, as much as technically feasible. It is clear that models must be "tuned" to meet local conditions in order to provide more accurate results. Otherwise, uncalibrated modeled results will not provide the necessary foundation for regulatory decision making. Modeling science continues to develop as new chemistry and better meteorology are incorporated.

With respect to regional haze modeling, NDDH spent significant technical resources and time "calibrating" EPA's default model, by nesting CALPUFF within CMAQ for more refined treatment of plume dispersion than would have otherwise been accomplished with the CMAQ model. The hybrid CMAQ-CALPUFF model was "tuned" to local monitored results and then used to project emissions for the glide path. It was clear that the NDDH's technical efforts provided a more accurate model in most situations. For future modeling, Great River Energy encourages NDDH to continue to use the most up-to-date modeling science, and to continue to calibrate these models with actual monitored data to ensure their relative accuracy.

The glide path is a "goal" and not an absolute, as defined by rule. "Natural," or non-manmade, and international sources are both significant and outside of NDDH control.

NDDH must preserve its ability to adjust the glide path for non-manmade and international emissions, which are completely outside of its control. As part of the weight of evidence, NDDH has modeled a scenario that eliminates all North Dakota emission sources that were used in the baseline. Even "zero"ing these emissions, NDDH demonstrates that the state cannot hit the first reasonable progress goal in 2018. In short, the international and non-manmade emissions are more significant in achieving "natural background" conditions than ND sources contained in the modeling database. By adjusting the glide path to exclude non-manmade and international emissions, as part of its weight of evidence, NDDH can more accurately demonstrate reasonable progress towards natural background conditions in 2064 through reductions over which it has control.

The BART rule treats smaller, non-presumptive sources (less than 750 MW) differently. EPA determined that these smaller sources should not be held to presumptive limits, unless the state exercises its discretion in order to meet reasonable progress goals.

It is important to note that significant technical and financial resources were spent to provide the complete BART evaluations and other supporting documentation. National emission control experts, including but not limited to Alstom, URS, and the Washington Group, were hired to provide engineering estimates based on their knowledge of recently installed controls, material costs, and site specific limitations. Their site specific recommendations should be considered more accurate than comparable information that could have been derived from older cost manuals, which are then adjusted for inflation, as suggested by the Federal Land Managers.

EPA clearly established presumptive BART emission rates for sources greater than 750 MW. These emission rates were deemed cost effective based on EPA's cost per ton estimates. NDDH BART determinations represent higher cost effective determinations than the BART rule. As an example, NDDH appears to use a somewhat arbitrary and largely unsubstantiated $3600/ton cost effectiveness threshold, as compared to ~$1000/ton in the BART rule. Great River Energy provided an analysis of cost effective controls as supported by the BART rule in our Cost Effectiveness Memo, dated July 3, 2007, which was included as an appendix in Coal Creek and Stanton stations' final BART determinations.

Given the inaccuracy of the model(s), as discussed, and the costly control of emissions, it is imperative that reasonable, cost effective determinations be consistently applied, not only in North Dakota but in the region, to ensure competitive energy production. The Regional Haze and BART rules have distinct requirements to make reasonable progress towards a goal of natural background conditions, in a cost effective manner, as deemed appropriate by the North Dakota Department of Health.

Although more than the rule requires, Great River Energy generally supports NDDH BART determinations as being within their statutory discretion to meet glide path goals.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services
Great River Energy

Cc: Greg Archer, GRE
Deb Nelson, GRE
Diane Stockdill, GRE
Steve Smokey, GRE