United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

IN REPLY REFER TO:

TAKE PRIDE IN AMERICA

January 14, 2011

N3615 (2350)

Shelley Schneider
Air Quality Division Administrator
Nebraska Department of Environmental Quality
1200 N Street, Suite 400
Lincoln, Nebraska 68509-8922

Dear Ms. Schneider:

On November 16, 2010, we received Nebraska's draft State Implementation Plan to address regional haze. We appreciate the opportunity to work closely with the State through the initial evaluation, development, and review of this plan.

This letter acknowledges that the U.S. Department of the Interior, National Park Service and U.S. Fish and Wildlife Service have conducted a substantive review of your proposed Regional Haze Rule implementation plan in fulfillment of your requirements under the federal regulations 40 CFR 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination regarding the document's completeness and, therefore, ability to receive federal approval from EPA.

As outlined in a letter to each State dated August 1, 2006, our review focused on eight basic content areas. These content areas reflect priorities for the Federal Land Manager agencies, and we have enclosed comments associated with these priorities.

We look forward to your response, as per section 40 CFR 51.308(i)(3). For further information regarding our comments, please contact John Bunyak of the National Park Service at (303) 969-2818 or Tim Allen of the Fish and Wildlife Service at (303) 914-3802.

Again, we appreciate the opportunity to work closely with the State of Nebraska to improve visibility in our Class I national parks and wilderness areas.

Sincerely,

Patricia F. Brewer

Patricia F. Brewer
Acting Chief, Air Resources Division
National Park Service

Sincerely,

Sandra V. Silva

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service

Enclosures

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ARD-DEN: Permit Review Group, Reading and Project File,
ARD-DEN:pbrewer:pb:01/14/11:x2153:NE RH SIP 01-14-11.Ltr.doc

National Park Service and U.S. Fish and Wildlife Service Comments
Nebraska Draft Regional Haze State Implementation Plan (SIP)
January 14, 2011

The National Park Service and Fish and Wildlife Service received Nebraska's draft regional haze state implementation plan (SIP) on November 16, 2010. We appreciate the opportunity to review the draft plan. The National Park Service and Fish and Wildlife Service provided recommendations to the Nebraska Department of Environmental Quality (NDEQ) in a letter dated August 2006 that detailed our priorities in reviewing the state plans. We address those priorities in our comments below. We are available to assist NDEQ in addressing our recommendations.

Reasonable Progress

Fundamentally, we are concerned that NDEQ has not met the requirement stated in the Regional Haze Rule Section 308(d)(3):

> Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State which may be affected by emissions from the State. **The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas.**

The draft SIP does not meet this requirement. The reasonable progress goals established by South Dakota for Badlands and Wind Cave National Parks, by Colorado for Rocky Mountain National Park, by Oklahoma for Wichita Mountains, and by Missouri for Mingo Wildlife Refuge and Hercules Glade Wilderness Area, as well as other Class I areas, assume that NDEQ will require presumptive BART controls for the Gerald Gentleman and Nebraska City power plants as modeled by the Western Regional Air Partnership (WRAP) and the Central Regional Air Partnership (CENRAP). NDEQ proposes not to require controls of sulfur dioxide (SO_2) for any of the BART units. NDEQ's long term strategy does not include the controls required to meet its contribution to the reasonable progress goals established by its neighboring states through the RPO process.

Point source SO_2 emissions account for 78% of total SO_2 emissions in Nebraska's 2002 inventory. Electric generating units (EGU) account for 92% of point source SO_2 emissions. Section 8.3.1.3 indicates that the 2018 inventory assumes significant reductions in SO_2 from electric generating units based on assumptions of the Integrated Planning Model. NDEQ does not document any actual SO_2 controls. It can be inferred that no reductions in SO_2 emissions from point sources are expected and that, based on Tables 8.1 and 8.3, SO_2 emissions from Nebraska in 2018 are underestimated by 21,218 tons, or 25% in the CENRAP and WRAP 2018 modeling. Nebraska does not discuss this discrepancy in Chapter 11 when presenting results of the 2018 source apportionment modeling or 2018 visibility projections for Class I areas.

EPA Region 6 in its proposed Federal Implementation Plan for San Juan Generating Station cites the emissions assumptions used in the WRAP modeling as evidence that San Juan Generating Station should be required to meet those emissions limits to support the reasonable progress goals set by neighboring states for their Class I areas. Similarly, Nebraska should require SO_2 controls consistent with the emissions assumptions used in the CENRAP and WRAP modeling and used by neighboring states, particularly Colorado and South Dakota, in setting reasonable progress goals for their Class I areas.

Best Available Retrofit Technology (BART)

We have several concerns with the BART analyses for Nebraska City Unit 1 and Gerald Gentleman Units 1 and 2. Please include a description of the emissions for the BART eligible units. Appendix 10.1 indicates that Gerald Gentleman Units 1 and 2 combined have potential SO_2 emissions of 79,200 tons/year and Nebraska City Unit 1 has potential SO_2 emissions of 45,696 tons/year. Please confirm and provide the actual annual SO_2 emissions from the 2002 CENRAP inventory for these three units, similar to the nitrogen oxide (NO_x) information in Table 8.5.

Five Factor Analysis

In Chapter 10, please provide a summary of the five factor analyses for Gerald Gentleman and for Nebraska City. The information was very difficult to ascertain from the current discussion in Chapter 10. The BART analyses can be summarized in the SIP Narrative and can reference the appropriate appendices for further information.

- Step 1: Identify the available retrofit technologies for SO_2 and NO_x. For SO_2 this should include lime spray dryer and dry sorbent injection as control options with lower water use requirements than wet flue gas desulfurization. For NO_x this should include selective non-catalytic reduction (SNCR) technology in addition to selective catalytic reduction (SCR).
- Step 2: Eliminate technically infeasible options.
- Step 3: Evaluate effectiveness of control options.
- Step 4: Evaluate impacts and document results.
- Step 5: Select Best Available Retrofit Control

Presumptive Controls for Nebraska City

EPA Region 7 provided guidance to Nebraska in a letter dated January 23, 2009. that the total plant capacity (BART plus non-BART units) is to be used to determine if an Electric Generating Unit (EGU) is greater than 750 MW and that any units in existence at the time of the BART determination are to be included in the total plant capacity. BART units at a facility greater than 750 MW are subject to presumptive controls. Given that Nebraska City Unit 1 alone is 616 MW, Nebraska needs to seriously consider all feasible SO_2 control options, and the presumptive SO_2 limit, as part of the five factor analysis. The text in Section 10.5 incorrectly refers to Unit 2 as BART eligible. Please provide the MW capacity of Units 1 and 2. It is unacceptable that Nebraska only discusses the legal requirement for presumptive controls rather than discussing the BART analysis and visibility impacts from Unit 1. In Table 10.5, the costs for a scrubber are less than $2000/ton and the visibility improvement from a scrubber are close to 0.5dv at a single Class I area. If Nebraska considered the visibility benefits at all the affected Class I areas, the benefits of the investment would be greater. Why was dry sorbent injection not evaluated for SO_2 controls? Why was Selective Non-Catalytic Reduction not evaluated for NO_x controls?

Gerald Gentleman
The BART determination is not acceptable as written. We disagree with Nebraska's BART determination of no SO_2 controls for Gerald Gentleman. Was dry sorbent injection considered? If not, why not? Nebraska provides an elaborate justification that limited water availability prohibits the application of wet flue gas desulfurization (FGD) at Gerald Gentleman without discussing the viable alternatives that are being used in western states. The economic factors influencing the economy of Nebraska are much greater than the possible retirement of irrigated acreage to obtain water rights for the power plant.

The Fish and Wildlife Service's Nebraska Field Office has reviewed the Nebraska water use discussion and has provided the attached comments that Nebraska has overstated the magnitude of offset required (see attached comments).

Additional comments on these two facilities are in the attached documents.

Additional comments on specific chapters are detailed below.

Chapter 6 Baseline, Current, and Natural Visibility Conditions
Please include summary of baseline conditions at key Class I areas (e.g. Badlands, Hercules Glade) impacted by Nebraska emissions to establish the relative contributions of pollutant species, seasonal trends in pollutant contributions, and priority for emissions controls. Because the Class I areas are geographically distant, the priority for emissions controls may differ among the Class I areas.

Chapter 7 Monitoring Strategy
Measurements at IMPROVE protocol sites and from special studies are discussed but no results are presented. How are the ammonia monitoring data being used?

Chapter 8 Emissions Inventory
The discussion of area source contributions to particulate matter (PM10) in the 2002 inventory is good. According to values in Table 8.1, area sources contribute 97% of ammonia (NH_3) emissions in Nebraska in 2002. Please add for NH_3 the same discussion and piechart as presented in Figure 8.3 for PM10. We disagree with ignoring NH_3 as a contributing pollutant, even if it is not a criteria pollutant. Please include a discussion of the change in NH_3 in 2018 in Table 8.3 and Section 8.3.1.5.

Please amplify the discussion of the 2018 projections to provide better explanation of the source categories contributing to point source emissions of SO_2 and NO_x. This information was not presented in either Appendix 8.2 (SMOKE reports in Microsoft Access) or Appendix 9.1 (ENVIRON technical report). This information is critical to supporting an adequate reasonable progress analysis.

Chapter 10 BART
See our general comments above and specific comments in the attached documents.

Please include the CENRAP BART Modeling Protocol in the Appendices as it has been referenced in the BART Modeling Protocol for Gerald Gentleman and Nebraska City.

Chapter 11 Reasonable Progress/Long Term Strategy
The SIP is missing the required four factor analysis evaluating reasonable control measures for sources in Nebraska.

Table 11.1 reports the net improvement in Light Extinction at neighboring Class I areas based on source apportionment modeling and what appear to be incorrect assumptions for SO_2 emissions in Nebraska. If the emissions assumptions are invalid, Nebraska's demonstration of reasonable progress is also invalid. Nebraska is not achieving the modeled emissions reductions and Nebraska's conclusion that no additional control measures are warranted is not supported.

Section 11.2: We note that Colorado in its regional haze SIP specifically mentions consultation with Nebraska on the BART determination for Gerald Gentleman due to the plant's impact to Rocky Mountain National Park. Nebraska does not include Colorado in its summary.

South Dakota's SIP lists a 36% reduction in Nebraska SO_2 emissions used in setting reasonable progress goals for Badlands and Wind Cave National Parks. This is 23,623 tons lower than we infer is appropriate based on no EGU SO_2 controls in Nebraska. This disconnect should be addressed in consultation with South Dakota and EPA Regions 7 and 8.

Section 11.3.2: Please include discussion about how the visibility improvement goals under the regional haze rule are incorporated in Nebraska's Prevention of Significant Deterioration program.

Section 11.3.7: Nebraska must re-evaluate what reductions are necessary to support the reasonable progress goals of neighboring states. The regional haze rule requires that the State include in its long term strategy all measures needed to achieve its apportionment of emission reductions and to identify all anthropogenic sources of visibility impairment considered in developing the long term strategy. Nebraska needs to demonstrate that its emissions sources are being controlled and that Nebraska is making reasonable progress in reducing anthropogenic emissions.

BART Comments on Omaha Public Power District Nebraska City Station Unit #NC1

January 14, 2011

Omaha Public Power District's (OPPD) Nebraska City Station contains one operating 650 MW coal-fired (Powder River Basin coal) boiler (NC1), with a second 660 MW coal-fired boiler currently permitted and under construction (NC2). Since NC2 has been permitted it is considered part of the electric generation capacity of Nebraska City Station and as such the two permitted emission units within Nebraska City Station generate more than 750 MW of electricity. Electric Generating Units within a 750 MW power plant which are greater than 200 MW in size are subject to specific, presumptive control requirements for SO_2 and NO_x emissions under the Environmental Protection Agency (EPA) Best Available Retrofit Technology (BART) Guidelines.[1] Of course, the only unit within the facility that is subject to the presumptive requirements of BART is NC1.

Even setting aside the presumptive requirements discussion for a moment, the SO_2 control alternative of Spray Dryer Absorber (SDA) with fabric filter was assumed to meet a control level of 0. 10 lb./MMBtu, which is more stringent than the presumptive 0.15 lb./MMBtu control level. The $1,636 per ton of SO_2 controlled using the SDA system is very reasonable. Many examples of proposed SO_2 control for BART can be cited that far exceed $1,636 per ton. Some examples are Boardman, OR - $3,053/ton; Brayton Point, MA - $3,043/ton; Bridger, WY $2,551/ton; Canal Station, MA - $3,170/ton; Martin Drake, CO - $2,765; Johnston, WY - $4,743; Kincaid, IL - $4,274; Mystic Station, MA - $4,270; Silver Bay Power, MN - $7,309; Salem Harbor, MA - $3,043; Stanton, ND - $2,006 and Taconite Harbor, MN - $5,300. The EPA BART Guidelines state, "A reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time."[2] In summary, $1,636 per ton for SDA with a fabric filter is reasonable and should be considered as BART for the NC1 unit.

The $78.9 million cost per deciview of visibility improvement at Hercules Glades for installation of SDA with a fabric filter was considered by the Nebraska Department of Environmental Quality (NDEQ) to trump the reasonable cost per ton as a reason to reject this SO_2 control alternative. Chapter 8 of the Regulatory Impact Analysis (RIA) the EPA prepared for the Regional Haze rule stated that high cost control measures that have only minimal effect on visibility improvement can be avoided. The functional words are "high cost control measures". SDA with fabric filter was shown above to *not* be a high cost control measure. Correspondingly, this control alternative should not be dismissed solely on the basis of a higher cost of visibility improvement at only one Class I area.

Further, the Clean Air Act, Section 169A(g)(2) states:

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[1] See 40 CFR Part 51, Appendix Y, Section IV.E.4 and 5.

[2] Ibid., See Section IV,D.Step 4,f.

". . . 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 non-air 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."

This wording indicates that the various considerations listed are to be used for help in determining a "best" available retrofit technology from among the various alternatives being considered. It does not state that a questionable outcome for any particular consideration may result in the outright dismissal of all choices for selection of a control technology.

There is a single conceptual idea presented in the EPA BART Guidelines from Section IV.D.Step 4, "Evaluate Impacts and Document the Results" to Section IV.D.Step 4.i, "How do I analyze non-air quality environmental impacts?" to Section IV.D.Step 5, "Evaluate Visibility Impacts" to Section IV.E, "How do I select the "best" alternative using the results of Steps 1 through 5?" The single concept is that these sections present methods for deciding which alternative control is the "best" alternative from among the technically feasible and cost feasible alternatives. These sections do not provide a means to entirely delete all alternatives from consideration.

This position then addresses the NDEQ concern that both SO_2 control alternatives, the wet scrubber and SDA will require obtaining water rights that may be detrimental to stream flows in Nebraska. The EPA BART Guidelines state, ". . . where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART."[3] First, this provides a good basis for selecting SDA over the wet scrubber. Second, SDA should be the selected alternative for BART, because NDEQ likely cannot show that water availability in Nebraska is more acute than in many other Western states which have installed SDA or other SO_2 controls that require additional water.

OPPD made judgments on cost per deciview based upon only the most impacted Class I area, Hercules Glades. We continue to believe that it is appropriate 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. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. If emissions from Nebraska City Station are reduced, the benefits will be spread well beyond only the most impacted Class I area, and this must be accounted for.

NDEQ proposes to require that OPPD meet the NO_x presumptive emission limit of

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[3] Ibid., See Section IV,D.Step 4,i.2.

0.23 lb/MMBtu by installing retrofitted Low NO_x Burners (LNB) combustion control technology to complement the existing over-fire air system (OFA) at an estimated cost of $136 per ton and $4.6 million/deciview of visibility improvement. OPPD proposes no additional NO_x, SO_2 or particulate matter (PM) BART controls. OPPD cited the reasons for no additional controls were excessive cost per deciview for Selective Catalytic Reduction (SCR) for NO_x control, excessive cost per deciview for a spray dryer absorber (SDA) for SO_2 control and "negligible impact" on visibility for PM control alternatives.

The addition of SCR to the proposed LNB/OFA results in $2,706 cost per ton of NO_x control. This is considered as a reasonable cost. Some other examples of proposed BART using SCR include Boswell Energy Center, MN - $3,201/ton; Healy, AK - $3,374; Jim Bridger, WY - $2,298; and Boardman, OR - $3,096. This alternative was discarded on the basis of excessive cost per deciview ($82.4 million/dv at Hercules Glades). The same arguments that were discussed above for SDA apply to installation of LNB/OFA/SCR as BART.

Page 7 of the 2007 OPPD BART Analysis document indicates that cost estimates were developed following guidance provided in the January 2002 OAQPS Control Cost Manual, using "limited vendor data obtained from various vendors in 2003" and then "scaled-up" to the present. Since it has been almost eight years since the 2003 vendor cost estimates were made, OPPD should obtain current cost estimates for all alternatives rather than simply scaling old 2003 information to the present. Current vendor cost estimates may be quite different and the errors of scaling could be large. In an effort to make OPPD's results for all control alternatives comparable to the universe of other companies' BART determinations, cost calculations based on use of the most recent OAQPS Control Cost Manual should be performed.[4]

Regarding PM control through continued use of the existing electrostatic precipitator (ESP), it should be noted that the EPA BART Guidelines provide that upgrades/improved operation should be considered as a BART alternative. The addition of collection fields should be considered as an upgrade as indicated in the EPA BART Guidelines.[5]

Section 3.1 of the 2007 OPPD BART Analysis document attempts to make a case that certain visibility improvements are "well below the minimum perceptible dV change". It is incorrect to dismiss a control strategy on the basis that the resulting improvement is not perceptible or significant. EPA states in the preamble to its BART Guidelines that, "Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I areas. Thus, we disagree that the degree of impairment should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment."[6]

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[4] Ibid., See Section IV.D.Step 4.a.5.
[5] Ibid., See Section IV.D.Step 3.4.
[6] See 40 CFR Part 51, Appendix Y. The U.S. Environmental Protection Agency finalized its BART Guidelines on June 15, 2005, and published the preamble and final rule text in the Federal Register on July 6, 2005. The rulemaking action added Appendix Y to Part 51, titled "Guidelines for BART Determinations Under the Regional Haze Rule." See Preamble, 70FR30129, middle column.

Comments on Proposed BART Permits for Nebraska Public Power District (NPPD) Gerald Gentleman Station (GGS) Units #1 and #2

January 14, 2011

Nebraska Public Power District (NPPD) operates the Gerald Gentleman Station (GGS), which includes two Electric Generating Units (EGUs), near Sutherland, NE. GGS includes two BART-eligible boilers which burn pulverized Powder River Basin (PRB) sub-bituminous coal (8,576 Btu/lb; 0.30 % sulfur; 4.69% ash in 2001). EPA's Clean Air Markets (CAM) database shows that, in 2009, GGS ranked #48 (of 1,230 facilities) in SO_2 emissions at 31,931 tons, and ranked #20 in NO_X emissions at 14,987 tons. The useful remaining life of GGS Units 1 and 2 is greater than 20 years under the current NPPD energy resource plan. Therefore the remaining useful life has no impact on the annualized estimated control technology cost at this time.

The plant is located within 400 km of three Class I areas (Badlands, Wind Cave, and Rocky Mountain National Parks) which are administered by the National Park Service. Modeling analyses have shown that GGS causes visibility impairment in the Badlands National Park (NP) @ 2.9 deciviews (dV) three-year average 98th percentile impact, Wind Cave NP (2.5 dV), Rocky Mountain NP (1.1 dV), and Wichita Mountains Wilderness (1.2 dV). GGS also contributes to visibility impairment at the Hercules Glades (0.7 dV) and Mingo (0.5 dV) Class I Wilderness areas. The cumulative impact of GGS on visibility is 9.3 dV.

Unit 1 is a dry-bottom, wall-fired boiler rated at 665 MW (net). Unit 1 is equipped with a fabric filter to control particulate matter (PM_{10}). It appears that Low-NO_x Burners (LNB) and Over-Fire Air (OFA) were installed 2005 – 2006 to reduce nitrogen oxides (NO_x) from about 0.45 pounds per million Btu (lb/mmBtu) and 12,000 – 14,000 tons per year (tpy) to about 0.22 lb/mmBtu and about 5,000 - 6,000 tpy.[1] There are no controls for sulfur dioxide (SO_2), which typically is emitted at 0.5 – 0.6 lb/mmBtu and 14,000 – 17,000 tpy. CAM data show that, in 2009, GGS Unit 1 ranked #82 (of 3,563 units) in SO_2 emissions at 15,805 tons, and ranked #57 in NO_X emissions at 5,446 tons.

Unit 2 is a dry-bottom, wall-fired boiler rated at 700 MW (net). Unit 2 is equipped with a fabric filter to control particulate matter (PM_{10}). There are no controls for SO_2, which typically is emitted at 0.5 – 0.6 lb/mmBtu and 14,000 – 17,000 tpy. There are no controls for NO_x, which typically is emitted at 0.30 – 0.35 lb/mmBtu and 8,000 – 10,000 tpy. CAM data show that, in 2009, GGS Unit 2 ranked #80 (of 3,563 units) in SO_2 emissions at 16,125 tons, and ranked #11 in NO_X emissions at 9,540 tons.

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[1] According to NDEQ, "On January 4, 2006, the Department received a PSD Construction Permit application for the replacement of Unit 1's burner equipment system including an overfire air port system. NPPD installed new Low NOx Burners (LNB) on Unit 1 because the existing burners were near the end of their useful life and to be pro-active in installing expected Best Available Retrofit Technology (BART) controls. A PSD construction permit was issued to GGS for the installation of the LNB on Unit 1 on August 18, 2006. A PSD permit was required for the modification due to the expected increase in carbon monoxide emissions as a result of the LNB installation."

In August of 2008 we filed comments regarding NPPD's BART analyses. We are updating our comments to reflect new information obtained since 2008.

BART Analyses

As noted by NPPD, the five basic steps of a case-by-case BART analysis are:
1. *Identify All Available Retrofit Control Technologies.* Control technologies should include pollution prevention, use of add-on controls and combinations of the two.
2. *Eliminate Technically Infeasible Options.* Technologies demonstrated to be infeasible based on chemical, physical, and engineering principles are excluded from further consideration.
3. *Evaluate Control Effectiveness of Remaining Control Technologies.* Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction and are evaluated following a "top-down" approach similar to BACT analyses.
4. *Evaluate Impacts and Document Results.* Impacts that should be considered for each control technology include: cost of compliance, energy impacts, non-air quality environmental impacts, and the remaining useful life of the unit to be controlled.
5. *Evaluate Visibility Impacts.* Modeling should be performed on the pre- and post-control emissions to determine the actual impact on visibility and assess the visibility improvement achieved and at what cost. This step does not need to be performed if the most stringent control technology is chosen.

However, before we begin a step-by-step discussion of the BART proposed for GGS for each pollutant, we provide some general comments.

Cost-Effectiveness Metrics

BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. For example, Oregon DEQ has established a cost/ton threshold of $7,300 based upon the premise that improving visibility in multiple Class I areas warrants a higher cost/ton than where only one Class I area is affected. In their BART proposal for the San Juan Generating Station, New Mexico used a range from $5,946/ton to $7,398/ton. Colorado uses $5,000/ton, New York uses $5,500/ton, and Wisconsin is using $7,000 - $10,000/ton as its BART threshold.[2]

One of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview. We believe that visibility improvement must be a critical factor in any program designed to improve visibility. Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed,

[2] "The Department used cost-per-ton reduced as the primary metric for determining the BART level of control. The upper limit for this metric was $7,000 to $10,000 per ton, which reflects historical low-end costs for controls required under BACT." BEST AVAILABLE RETROFIT TECHNOLOGY AT NON-EGU FACILITIES April 19, 2010, WISCONSIN DEPARTMENT OF NATURAL RESOURCES

spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation[3] of BART analyses across the U.S. reveals that the **average cost per dv proposed by either a state or a BART source is $14 - $18 million,**[4] with a maximum of $51 million per dv proposed by South Dakota at the Big Stone power plant. (For example, we note that OR DEQ has explicitly chosen $10 million/dv as a cost criterion, which is somewhat below the national average.)

NPPD has presented extensive information to support its contention that costs of pollution controls are increasing, and that this should be taken into account in these cost analyses. NPPD appears to have used cost escalation as its rationale to present a mix of costing techniques that borrow from the OAQPS Control Cost Manual (Cost Manual), and NPPD's consultant's proprietary methods. We agree with NPPD that inflation should be a factor in these cost analyses. In fact, we included just such a factor our own analyses that we discuss later in this document.

Much of NPPD's argument against installing pollution controls at GGS centers on the then-increasing worldwide costs of pollution controls in general; that is no longer true. According to a report prepared for the Utility Air Regulatory Group:[5]

> The recent moderation in the world economy has removed many of the supply barriers and eased cost escalation. The cost to retrofit FGD and SCR equipment is expected to moderate from peak levels observed in the last 24 months, but may not significantly decline. A key reason is the ever-increasing complexity of the host sites. As host units are older and of smaller generating capacity, there is less available space for control equipment. Frequently, convoluted and complex ductwork is required, increasing retrofit difficulty.

While the concern about complex retrofits may be true for eastern EGUs where the cap-and-trade programs allowed utilities to control the easiest and most cost-effective retrofits first, and leave the more complex retrofits for later (or never), no such "natural selection" process exists in Nebraska. There is no reason to believe that Gerald Gentleman would be an especially difficult retrofit.

Furthermore, if the NPPD cost argument were carried to its logical conclusion, then no EGU should be required to install any pollution control equipment that involves a large capital expenditure. Instead, we believe that pollution control is an inherent cost of doing business, and that NPPD must show why GGS would experience uniquely higher costs for pollution controls than would normally be considered reasonable.

Finally, BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors.

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[3] http://www.wrapair.org/forums/ssjf/bart.html

[4] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at $580,000 per day and $18.5 million per deciview."

[5] J.E. Chichanowicz Report "Current Capital Cost and Cost Effectiveness" - January 2010

Cost Estimation Methods

The cost estimates submitted by NPPD are severely lacking in the types of specific information needed to give them credibility. Although there are several methods for estimating costs, our experience leads us to believe that no one method is perfect and that the costing methods need to be tempered by real-world data. And, while NDEQ states that "NPPD used vendor quotes for the majority of the analysis," we found no documented actual vendor quotes in the materials made available for our review.[6] In that case, the BART Guidelines recommend use of the OAQPS Control Cost Manual:

> 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, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

Cost Escalation

NPPD included an escalation component in its cost estimates. Larry Sorrels, an economist at EPA's Office of Air Quality Planning and Standards (OAQPS) commented[7] upon use escalation factors to calculate the levelized cost of each technology.

> Estimating real annual costs means no use of escalation factors...

It is not appropriate to escalate costs into the future and compare them against current cost thresholds.

Inflation and the Allowance for Funds During Construction:

Mr. Sorrels also provided[8] insight on matters pertaining to **inflation** and the **Allowance for Funds During Construction** (AFUDC):

> On cost indexes, I prefer the CEPCI (Chemical Engineering Plant Cost Index) for escalating/deescalating costs for chemical plant and utility processes since this index specifically covers cost items that's pertinent to pollution control equipment (materials, construction labor, structural support, engineering & supervision, etc.). The Marshall & Swift cost index is useful for industry-level cost estimation, but is not as accurate at a disaggregated level when compared to the CEPCI. Thus, I recommend use of the CEPCI as a cost index where possible.
>
> I agree with including AFUDC in a capital cost estimate if this is already included in the base case as per a utility commission decision. Otherwise, I do not agree with its inclusion.

The CEPCI has declined since the NPPD analysis (see chart below)

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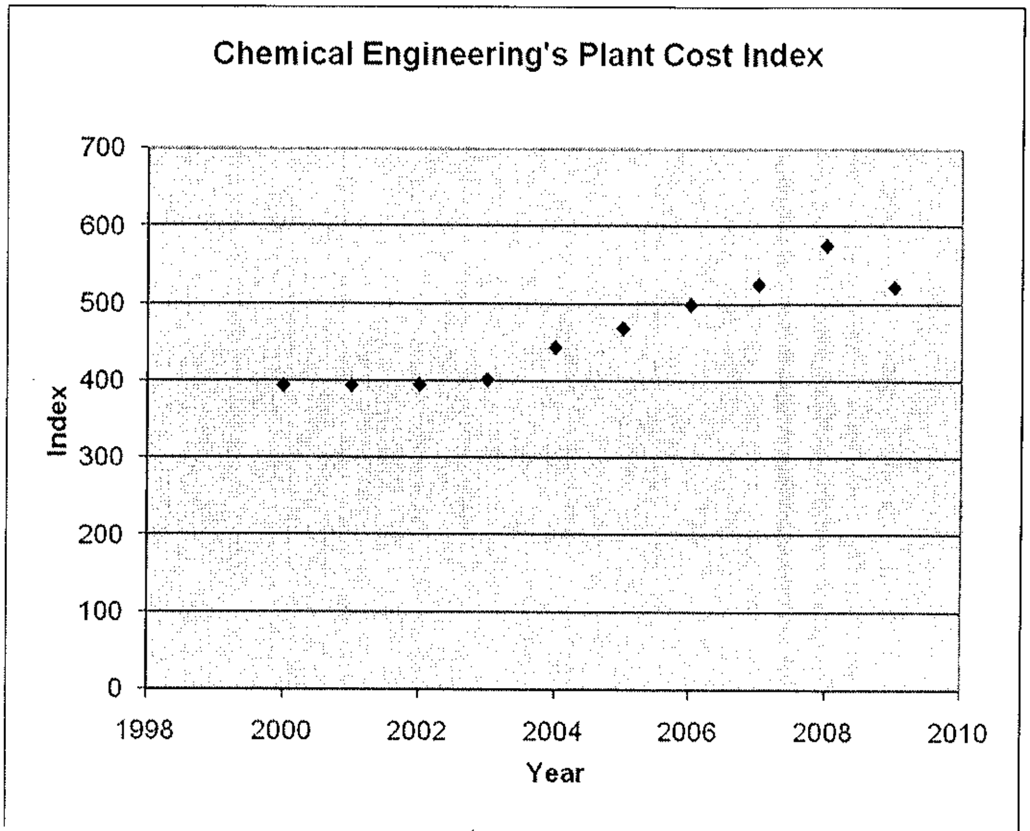
[6] The NPPD BART analysis contained such general statements as "Equipment costs were developed based on vendor budgetary quotes" and "Major equipment costs were based on vendor budgetary quotes." NDEQ refers to the "2008 S&L NPPD Study" but we were not provided a copy.

[7] E-mail dated September 7, 2010 to Don Shepherd of NPS.

[8] 7/21/10 e-mail to Don Shepherd



and, **as we will show later, NPPD included AFUDC costs that amount to scores of millions of dollars.**

Annual Costs

The Direct Annual Cost (DAC) component of the process is also important because it represents a significant portion of the Total Annual Cost. The methods presented by the Cost Manual for estimating DAC appear to be straight-forward and should accurately represent annual costs with no need for adjustment. **However, we note in our review of the BART analyses presented by NPPD that there appears to be a consistent significant overestimation of DAC.**

Visibility Improvement Metrics

NDEQ considered visibility improvements at Badlands NP, but effectively ignored potential improvements to visibility in the other Class I areas where GGS is also causing or contributing to visibility impairment. We continue to believe that it is appropriate 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. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. It follows that, if emission from the BART source are reduced, the benefits will be spread well beyond only the most impacted Class I area, and this must be accounted for.[9] While NDEQ presented data describing improvements to visibility at Badlands NP that would result from the various control scenarios it investigated, NDEQ still has not explained how it incorporated this information on impacts upon all Class I areas into its BART decision.

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available. For example, we understand that the Oregon Department of Environmental Quality used a similar approach in its analyses when it evaluated the benefits of various control strategies on all 14 of the Class I areas within 300 km of the Boardman power plant.

Average versus Incremental Cost-Effectiveness

Contrary to EPA guidance to consider both average and incremental cost-effectiveness, NDEQ appears to have relied excessively upon incremental costs and benefits when moving from a lower level of emission control to a higher level. Although NDEQ calculated the average costs of scrubbing SO_2 and concluded they were "reasonable," it reported only the incremental costs and benefits in the body of its SIP analysis. NDEQ's treatment of Selective catalytic reduction (SCR) is more troubling. While NDEQ correctly asserts that:

> Although SCR is a feasible control technology, it would be most practical to install SCR in combination with combustion controls...Therefore, the cost associated with installing LNB/OFA is linked to this control technology throughout the analysis.

NDEQ goes on to reject addition of SCR to LNB/OFA on the basis of excessive incremental costs and without estimating average cost-effectiveness of "SCR in combination with combustion controls":

> The NDEQ determined that the incremental cost for the addition of SCR is excessive and that LNB/OFA would be required for BART.

We believe that NDEQ must evaluate the cost-effectiveness of "SCR in combination with combustion controls" as it had recommended.

[9] For example, the cumulative benefits have been a factor in the BART determinations by NM, OR, and WY, as well as EPA in its proposals for the Navajo Generating Station and the Four Corners Power Plant.

BART for Sulfur Dioxide (SO_2)

Step 1: Identify All Available Retrofit Control Technologies and Step 2: Eliminate Technically Infeasible Options.

NPPD presented the following options and feasibility determinations:

Coal Desulfurization	Infeasible - not demonstrated for low-sulfur PRB coal
Pahlman Process	Infeasible - not demonstrated on large coal-fired boilers
Other Regenerative Processes	Infeasible – none have been demonstrated on large coal-fired boilers
Wet Scrubbing	Feasible based on demonstrated performance on many similar units
Dry Scrubbing	Feasible based on demonstrated performance on many similar units

NPPD and NDEQ erred by not considering Dry Sorbent Injection (DSI), which uses no water. "Dry sorbent duct injection is a means for utility and large boiler operators to reduce emissions of sulfur oxides. The effectiveness of dry sorbent injection is dependent on the type of sorbent, injection location, and system operating parameters...For higher removal requirements (greater than 50%), either trona or sodium bicarbonate is recommended. For systems equipped with baghouses (like GGS), trona is the more cost-effective sorbent since the residence time provided by the baghouse allows for this lower cost sorbent to be used."[10]

EPA states[11] that DSI can achieve up to 80% control efficiency. (While EPA also notes that DSI is an emerging technology for medium-to-small industrial boilers, that is because larger boilers typically are required to install the more-efficient wet or dry scrubbing systems.) For example, Nalco-Mobotec advertises that its DSI systems can achieve 50% - 80% SO_2 control.

Oregon Department of Environmental Quality (ODEQ) is requiring DSI as BART for the Boardman Power Plant. According to ODEQ, "*Dry sorbent injection* is considered to meet the BART requirements because it is cost effective and will provide significant visibility improvement (>0.5 dV) in at least the Mt. Hood wilderness [12]area. Based on installations on smaller boilers, DSI can achieve emission reductions of 30 to 70%. Considering the size of the Boardman unit (duct geometry and exhaust gas flow), a DSI system may perform in the lower range of the control effectiveness, but the effectiveness could be improved with additional operating experience. Therefore, DEQ proposes a limit of 0.40 lb/MMBtu (35% emission reduction) in 2014 to satisfy the BART requirements. The limit is lowered to 0.30 lb/MMBtu (51% emission reduction) in 2018. The limit in 2018 could be met by further refinements to the DSI system or in combination with ultra-low sulfur coal or supplemental fuels, such as biomass." (Please note that the Boardman EGU uses an electrostatic

[10] Jon Norman, P.E., James R. Paye, Keith Day, O'BRIEN & GERE ENGINEERS, INC. "DECISION MATRIX FOR DRY SORBENT DUCT INJECTION FOR CONTROL OF SULFUR OXIDE EMISSIONS FROM COMBUSTION PROCESSES" Paper # 6

[11] Air Pollution Control Technology Fact Sheet EPA-452/F-03-034

[12] Addendum to the DEQ BART Report for the Boardman Power Plant (November 30, 2010)

precipitator to control particulate (PM) emissions, which decreases the effectiveness of DSI versus a baghouse like GGS.)

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

NDEQ has underestimated the ability of modern SO_2 control systems. NDEQ effectively assumed that wet and dry scrubbing could achieve only 80% - 87% SO_2 control down to 0.1 - 0.15 lb/mmBtu. It appears that NDEQ evaluated scrubbing at both 0.15 lb/mmBtu and 0.1 lb/mmBtu, but provides no information on how those analyses were conducted. Unlike the retrofitting of NO_x controls that is highly dependent upon the existing boiler configuration, the SO_2 controls that could be added at GGS would be completely new, and should therefore be capable of performing as well as at a greenfield facility.

It is easier to achieve a higher SO_2 control efficiency on coals with higher inherent, uncontrolled emissions. And, as uncontrolled emissions increase, controlled emissions will also tend to increase despite the increasing SO_2 control efficiency. It follows that it is harder to achieve a higher control efficiency on a gas stream with a lower inlet SO_2 concentration, but easier to achieve a lower outlet concentration. So, if one can achieve lower emission rate on a "dirtier" gas stream, it would indicate a higher degree of scrubbing success. All of this must be considered when determining the level of SO_2 control that is feasible for a given coal.[13]

Inspection of Table 1.a. (below) reveals that wet FGD systems are achieving (e.g., Navajo Generating Station, Intermountain Power) or being proposed/permitted at 0.04 – 0.09 lb/mmBtu on coals with much higher uncontrolled emissions than currently seen at GGS. Based upon this data and a consideration of GGS' cleaner coal quality, we believe that a new wet FGD at GGS should be able to achieve 0.04 lb/mmBtu[14] (or lower) on a 30-day rolling average.

Table 1.a. Wet Scrubber SO_2 Rankings (30-day rolling averaging period)

SO_2				Coal Quality			Capacity	Emissions or Limits	Control
Facility Name	Unit	Status	Permit #	%S	(Btu/lb)	(lb/mmBtu)	MW	(lb/mmBtu)	(%)
NPPD-GGS (Proposed)	1&2		NE	0.30	8576	0.555	1365	0.040	92.8%
Colstrip	4	operating	MT	0.75	8487	1.546	778	0.093	94.4%
Colstrip	4	operating	MT	0.75	8487	1.546	778	0.091	94.5%
Intermountain Pwr	3	issued	UT-0065	0.75	11193	1.273	950	0.090	92.9%
Navajo	1	operating	AZ	0.53	10919	0.922	803	0.072	92.9%
Navajo	3	operating	AZ	0.53	10919	0.922	803	0.064	93.2%

13 For the sake of consistency, it is assumed that the SO_2 emission factor is dependent upon the coal type, but independent of the boiler type. The natural process of retention of sulfur in the ash is just as fundamental a characteristic of the coal burned as its sulfur content and its heating value. So, bituminous coals would emit 95% of their sulfur content as SO_2, while sub-bituminous coals would emit 87.5%, and lignites 75%.

14 For example, EPA proposed to permit the Desert Rock power plant at 0.06 lb/mmBtu (24-hour average) despite coal with almost three times the uncontrolled emissions as at GGS.

Sithe-Desert Rock		pending	EPA	0.82	8910	1.611	1500	0.060	96.3%
Sithe-Toquop		application	NV	1.4	8215	2.982	750	0.060	98.0%
Mustang		application	NM	1.56	8647	3.157	300	0.060	98.1%
Intermountain Pwr	2	operating	UT	0.48	11817	0.772	820	0.059	92.4%
Navajo	2	operating	AZ	0.53	10919	0.922	803	0.044	95.5%
FPL-Glades		application	FL	1.98	12324	3.053	2x980	0.040	98.7%
Taylor		application	FL	3.46	7475	8.100	800	0.040	99.5%

Inspection of Table 1.b. (below) reveals that semi-dry FGD systems are being proposed/permitted at 0.06 – 0.09 lb/mmBtu on coals with much higher uncontrolled emissions than currently used at GGS. Based upon this data and a consideration of GGS' even cleaner coal quality, we believe that a new semi-dry FGD at GGS should be able to achieve 0.06 lb/mmBtu (or lower) on a 30-day rolling average.

Table 1.b. Dry Scrubber SO2 Rankings (30-day rolling averaging period)

SO2				Coal Quality			Capacity	Emissions or Limits	Control
Facility Name	Unit	Status	Permit #	%S	(Btu/lb)	(lb/mmBtu)	MW	(lb/mmBtu)	(%)
NPPD-Gerald Gentleman (Proposed)	1&2		NE	0.30	8576	0.555	1365	0.060	89.2%
LS Pwr--High Plains	1	application	CO	0.66	8200	1.409	600	0.090	93.6%
Black Hills Pwr-WYGEN 3		issued	WY	1.20	7950	2.642	100	0.090	96.6%
LS Power-White Pine		draft permit	NV	0.66	8200	1.409	3x530	0.089	93.7%
Basin Electric--Dry Fork		permit	WY	0.47	7800	1.054	385	0.075	92.9%
Newmont Nevada		issued	NV-0036	0.45	8400	0.938	200	0.065	93.1%
LS Power-White Pine		draft permit	NV	0.3	8200	0.640	3x530	0.065	89.8%
LS Pwr--High Plains	1	application	CO	0.46	8200	0.982	600	0.065	93.4%
Sierra Pacific-Ely		application	NV	0.8	8100	1.728	2x750	0.060	96.5%

We call attention to the permit issued by Nevada to Newmont Nevada requiring its dry scrubber to meet the following limits on very low-sulfur coal:

Section V. Specific Operating Conditions (continued)
A. Emission Unit #S2.001 - Pulverized Coal Fired Boiler (continued)
2. NAC 445B.3405
a. Emission Limits (continued)
(7) Article 8.2.1.2 *Federally Enforceable SIP* - The discharge of sulfur to the atmosphere will not exceed **1,218.0** pounds per hour.
(8) NAC 445B.305 *BACT Emission Limit* – The discharge of SO_2 to the atmosphere will not exceed:
(i) While combusting coal with a Sulfur content equal to or greater than 0.45 percent (30-day rolling period), based on daily ASTM sampling:

(a) **0.09** pound per million Btu, based on a 24-hour rolling average period.
(b) 95% minimum SO_2 removal efficiency will be maintained across the system, based on a 30-day rolling period.
(ii) While combusting coal with a Sulfur content less than 0.45 percent (30-day rolling period), based on daily ASTM sampling:
(a) 0.065 pound per million Btu, based on a 24-hour rolling average period.
(b) 91% minimum SO_2 removal efficiency will be maintained across the system, based on a 30-day rolling period.

The Newmont Nevada permit indicates that a modern dry scrubber can achieve greater than the 80% maximum assumed by NPPD and NDEQ, even on low-sulfur coals.

In its "response to Comments," NDEQ appears to contend that, because some EGUs are not achieving the low SO_2 limits we suggest here, that GGS should not be expected to do so, either. We remind NDEQ that BART requires "**Best** Available Retrofit Technology," not "**Average** or **Worst** Available Retrofit Technology."

Step 4: Evaluate Impacts and Document Results.

NPPD's FGD costs are overestimated.

Dry Scrubber: NPPD has estimated that it would cost over $2,700/ton to control SO_2 using a dry scrubber at GGS (Table 2.a). While much of this cost is due to extensive baghouse modifications to accommodate the additional particulate generated in the dry scrubber, the over-$700 capital cost per kilowatt hour (kWh) appears unusually high, especially when compared to the $423/kWh that Great River Energy proposes to spend to add a dry scrubber to its Stanton Unit #1 in North Dakota.

Table 2.a. Gerald Gentleman — NPPD estimates **Dry FGD addition burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Gross) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Future Uncontrolled Emissions (tpy)	24,893	company report	24,893
Controlled Emissions (lb/mmBtu)	0.15	company report	0.15
Overall Control Efficiency (FGD)	74%	calculated	73%
Emission Reductions (tpy)	19,908	company report	19,908
Capital Cost	$ 490,796,000	company report	$ 490,796,000
Capital Cost ($/kW)	$ 738	calculated	$ 701
Annualized Cost	$ 54,258,500	company report	$ 54,258,500
Cost-Effectiveness ($/ton)	$ 2,726	company report	$ 2,726

Although we were unable to estimate operating costs, and thus total annual costs and cost-per-ton, due to a lack of information from NPPD, we were able to estimate capital costs based upon industry data[15] which lead to an estimated Capital Cost of $280 -

[15] J.E. Cichanowicz "Overview of Information on Project Control Technology Costs" October 2010

$420/kW. (For a 700 MW EGU like GGS 1 & 2, Capital Cost should be $200 - $300 million.) Even when we include NPPD's high costs for ductwork, stack, and baghouse modifications, our previous estimates of $374 - $393/kW appear much more reasonable than those of NPPD. It is likely that the $700+/kW capital cost estimates from NPPD were the highly influenced by the improper inclusion of over $120 million in "Escalation" costs and over $83 million in AFUDC costs. We also question a "Contingency" cost of over $149 million (15%) of a $987 million total; this is five times higher than the 3% contingency expense estimated by the Cost Manual.

Because the NPPD capital costs estimates were higher than we expected, we applied the Cost Manual methods to the NPPD cost analyses and our "adjusted" results are presented Table 2.b. below:

Table 2.b. Spray-Dry FGD at 0.15 lb/mmBtu

Dry FGD Cost Components	NPPD*		NPS**	
Direct Capital Cost	$	575,827,000	$	575,827,000
Indirect	$	47,452,000	$	16,608,200
Escalation	$	120,449,000	$	-
Sales/Use Tax	$	11,077,000	$	11,077,000
Contingency	$	148,745,000	$	17,274,810
AFUDC	$	83,302,000	$	-
Total Capital Cost	$	986,852,000	$	620,787,010
Total Capital Cost/kW	$	723	$	455
Capital Recovery Factor				0.0944
Levelized Capital Cost (w/ fan sized for FGD only)	$	80,013,000	$	58,597,902
Levelized O&M Cost	$	27,806,000	$	27,806,000
Levelized Outage Cost	$	698,000	$	698,000
Total Levelized Capital, Outage and O&M Cost	$	108,517,000	$	87,101,902
Tons SOx removed		40,426		40,426
Dry FGD cost-effectiveness ($/ton)	$	2,684	$	2,155

*DRY FGD AND ID FAN & AUXILIARY POWER CONCEPTUAL DESIGN COSTS

**Based upon OAQPS Control Cost Manual

If the Escalation and AFUDC costs were eliminated, and the Contingency cost were adjusted to the recommended 3%, the resulting $366 million reduction in dry scrubber costs would bring the Total Capital Cost down to a more realistic $455/kW. Using the NPPD O&M costs and SO_2 removal estimates in conjunction with our lower annual capital cost results in a cost-effectiveness of less than $2,200/ton.

Wet Scrubber: As shown in Table 3.a. (below), NPPD has estimated that it would cost over $2,700/ton to control SO_2 using a wet scrubber at GGS. Once again, NPPD estimates a capital cost/kWh of over $700. And, again, this appears unusually high, especially when compared to the $335 - $496/kWh that Basin Electric Power proposes to spend to add wet scrubbers to its Leland Olds Units 1 & 2 in North Dakota. Also in North Dakota, Minnkota Power is proposing to add a wet scrubber to its M.R. Young Unit 1 at a capital cost of $435/kWh.

Table 3.a. GGS —NPPD estimates **Wet FGD addition burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Gross) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Future Uncontrolled Emissions (tpy)	24,893	company report	24,893
Controlled Emissions (lb/mmBtu)	0.15	company report	0.15
Overall Control Efficiency (FGD)	74%	calculated	73%
Emission Reductions (tpy)	19,908	company report	19,908
Capital Cost	$ 514,909,500	company report	$ 514,909,500
Capital Cost ($/kW)	$ 774	calculated	$ 736
Annualized Cost	$ 54,225,000	company report	$ 54,225,000
Cost-Effectiveness ($/ton)	$ 2,724	company report	$ 2,724

Although we were unable to estimate operating costs, and thus total annual costs and cost-per-ton, due to a lack of information from NPPD, we were able to estimate capital costs based upon industry data[16] which lead to an estimated Capital Cost of $370 - $460/kW. (For a 700 MW EGU like GGS 1 & 2, Capital Cost should be $250 - $330 million.) Our previous capital cost estimates of $368 - $388/kWh appear much more reasonable than those of NPPD.

It is likely that the $700+/kW capital cost estimates from NPPD were the highly influenced by the improper inclusion of over $120 million in "Escalation" costs and over $83 million in AFUDC costs. We also question a "Contingency" cost of over $149 million (15%) of a $987 million total; this is five times higher than the 3% contingency expense estimated by the Cost Manual.

Because the NPPD capital costs estimates were higher than we expected, we applied the Cost Manual methods to the NPPD cost analyses and our "adjusted" results are presented Table 3.b. below:

Table 3.b. Wet FGD at 0.15 lb/mmBtu

Wet FGD Cost Components	NPPD*	NPS**
Direct Capital Cost	$ 597,727,000	$ 597,727,000
Indirect	$ 51,963,000	$ 18,187,050
Escalation	$ 126,848,000	$ -
Sales/Use Tax	$ 14,634,000	$ 14,634,000
Contingency	$ 155,308,000	$ 17,931,810
AFUDC	$ 88,599,000	$ -
Total Capital Cost	$ 1,035,079,000	$ 648,479,860
Total Capital Cost/kW	$ 758	$ 475
Capital Recovery Factor		0.0944
Levelized Capital Cost (w/ fan sized for FGD only)	$ 83,965,000	$ 61,211,911
Levelized O&M Cost	$ 24,485,000	$ 24,485,000
Levelized Outage Cost	$ -	$ -
Total Levelized Capital, Outage and O&M Cost	$ 108,450,000	$ 85,696,911

[16] J.E. Cichanowicz "Overview of Information on Project Control Technology Costs" October 2010

Tons SOx removed	41,338	41,338
Wet FGD cost-effectiveness ($/ton)	$ 2,623	$ 2,073

*WET FGD AND ID FAN & AUXILIARY POWER CONCEPTUAL DESIGN COSTS
**Based upon OAQPS Control Cost Manual

If the Escalation and AFUDC costs were eliminated, and the Contingency cost were adjusted to the recommended 3%, the resulting $387 million reduction in wet scrubber costs would bring the Total Capital Cost down to a more realistic $475/kW. Using the NPPD O&M costs and SO_2 removal estimates in conjunction with our lower annual capital cost results in a cost-effectiveness of less than $2,100/ton.

Step 5: Evaluate Visibility Impacts.

NDEQ estimates that reducing SO_2 emissions to 0.15 lb/mmBtu would improve visibility at Badlands NP (the only Class I area for which improvements was provided) by 0.785 dV, and by 0.845 dV at 0.10 lb/mmBtu, but we did not have sufficient data to evaluate the cumulative benefits of improving visibility at the other Class I areas. If the scrubbers achieved the lower emission rates that we believe are reasonable, then the visibility benefits would increase.

BART Determination for SO_2

NDEQ: Scrubber technology is a technically feasible SO_2 retrofit technology that could be implemented on GGS Units 1 and 2. Not taking the other environmental effects, except energy, into account, the average cost effectiveness of using scrubbing control technology is approximately $2,500 – $2,700 per ton SO_2 removed. The cost per ton removed seems reasonable. When evaluating the cost effectiveness in terms of the visibility benefit derived from scrubbing, the NDEQ assessed the average incremental visibility impairment improvement. The NDEQ also calculated the incremental cost per day of visibility improvement.

Over the three years of meteorology modeled, at 0.10 lb SO_2/MMBtu, the average incremental visibility impairment improvement cost is $132,816,547 per year per change in deciview impact. The average number of days the Badlands would expect to experience a contribution from GGS of greater than 0.5 dV would be 22 per year. This is a 39% reduction in the 56 days per year that the units contribute more than 0.5 dV. The average incremental cost per day of visibility improvement calculates to be $4,870,860 per day ($2,435,430 per unit).

Again, these values do not account for the added costs that would be incurred from other environmental impacts, except energy. These values are of the same magnitude as the OPPD Nebraska City Unit 1 BART evaluation. There, NDEQ determined that additional SO_2 controls were not reasonable, in part due to the excessive cost per benefit in terms of visibility improvement (i.e., $/yr/dV).

Here in the case of NPPD GGS Units 1 and 2, NDEQ has serious concerns over the current availability of water to supply the scrubber and the potential effects of the depletion of water on threatened and endangered species in the Platte River Valley area. Since the incremental visibility impairment improvement cost is so large compared to similar improvements in visibility using LNB/OFA technology and most importantly,[17] the potential for other serious environmental impacts, the NDEQ has determined that it is inappropriate to require the installation of SO_2 scrubbing technology as BART at this time. NPPD shall instead continue to utilize low sulfur coal. However, additional SO_2 controls may be required in the future for purposes of "reasonable further progress." At that time, available control technologies would be evaluated, as well as water availability, whether water availability can reasonably be resolved, and the ability to mitigate potential threats to endangered species in the Platte River Valley area.

The costs to transport water increased the total annualized cost associated with the installation of Wet FGD at GGS to $2,108,450,000. The average cost effectiveness of this control technology is $52,956 per ton SO2 removed ($2,108,450,000 / 39,815 tons SO2 removed) based on an emissions rate of 0.15 lb/MMBtu. The average cost effectiveness of this control technology at an emissions rate of 0.1 lb/MMBtu is approximately $48,877 per ton SO_2 removed ($2,108,450,000/43,138 tons SO2 removed).

The NDEQ determined that the costs to transport water made scrubbing costs prohibitive for NPPD as a BART SO_2 measure.

NPS SO_2 BART Conclusions:

NPPD and NDEQ erred by not considering Dry Sorbent Injection (DSI), which uses no water.

We have presented information showing that several EGUs are operating at, or have been proposed or permitted with much lower SO_2 limits than evaluated by NDEQ. NDEQ should evaluate a SO_2 limit that reflects the capabilities of modern scrubbers.

Use of EPA guidance and data results in capital cost estimates that are significantly lower than those presented by NPPD. NPPD should re-do its scrubbing analyses in the format presented by the OAQPS Control Cost Manual[18] and model the effects on all Class I areas of reducing SO_2 to 0.04 – 0.06 lb/mmBtu to provide the information to develop the "fifth factor" in the BART process.

NO_x BART[19]

NDEQ has combined these two boilers for its analysis, even though NO_x emissions from these boilers differ substantially.[20] We continue to believe that separate analyses are

[17] How is LNB/OFA relevant to SO_2 scrubbers and water?
[18] It would be very helpful if NPPD would provide vendor quotes and supporting documentation for major cost items.
[19] Presumptive BART for these wall-fired boilers burning sub-bituminous coal is 0.23 lb/mmBtu.
[20] In response to our previous comment on this issue, NDEQ replied that "The temperature issue was discussed with NPPD. The two units are different and could not be evaluated in combination."

necessary. NDEQ has proposed only LNB and OFA as NO_x controls (They have already been installed on Unit 1) to meet the presumptive BART limit.

Step 1: Identify All Available Retrofit Control Technologies and Step 2: Eliminate Technically Infeasible Options.

NDEQ has eliminated Selective Non-Catalytic Reduction (SNCR) from consideration without sufficient justification on the basis that it is not technically feasible because of high temperatures measured in a similar boiler. However, it appears from the CAM data that NO_x emissions from the two boilers at GGS are significantly different. Therefore, we question not only NDEQ's assumption that it can eliminate SNCR on the basis of temperature characteristics at a distant boiler, but also whether it can assume that the two boilers at GGS are so similar that they can be evaluated in combination, not individually. (This same concern applies to the rest of NPPD's analyses of NO_x controls.) Thus, NPPD should show, with data specific to each of the GGS boilers, that this is the case at the GGS facility also. However, in response to our previous comment on this issue, NDEQ replied that "The temperature issue was discussed with NPPD. The two units are different and could not be evaluated in combination." This indicates that NDEQ's rejection of SNCR on the basis of similarity to another boiler is not valid.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

NDEQ has underestimated the ability of modern NO_x control systems: A significant reason for the higher cost-effectiveness of this option estimated by NDEQ is the low NO_x control efficiency it assumed for a technology that should be able to achieve 90% control. NDEQ estimates that addition of SCR can reduce NO_x by 75% - 83% to 0.08 lb/mmBtu.

SCR is different from many other control technologies in that its efficiency is not highly dependent upon the concentration of the pollutant to be controlled.[21] Instead, SCR efficiency is primarily influenced by the design of the catalyst reactor, that is, the volume of the catalyst, its cross-sectional area, number of layers, and measures to prevent blinding and deactivation, as well as replacement schedule. If it is necessary to achieve a high degree of removal efficiency on an inlet stream with a low concentration, more catalyst can be included in the design. It is generally understood that NO_X reductions of approximately 90% or more may be achieved with SCR systems.[22] And, according to the June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO_2

[21] However, as noted below in an excerpt from the EPA Control Cost manual, at very low inlet concentrations, removal efficiency may be lower:

> In general, higher uncontrolled NOx inlet concentrations result in higher NOx removal efficiencies due to reaction kinetics. However, NOx levels higher than approximately 150 parts per million (ppm), generally do not result in increased performance. Low NOx inlet levels result in decreased NOx removal efficiencies because the reaction rates are slower, particularly in the last layer of catalyst.

[22] According to the Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants" (published in May 2009), "By proper catalyst selection and system design, NO_X removal efficiencies exceeding 90 percent may be achieved."

and NO_X Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier, "An excellent example of the significant investment many utilities have made over the past decade is American Electric Power (AEP), one of the largest public utilities in the U.S. with 39,000 MW of installed capacity with 69% of that capacity coal-fired. AEP is under a New Source Review (NSR) consent decree signed in 2007 that requires the utility install air quality control systems to reduce NO_X by 90%..."

We are aware of vendor guarantees of 0.05 lb/mmBtu,[23] and understand that major vendors are designing SCR systems to achieve 0.02 lb/mmBtu[24] on coal-fired boilers.

Operational evidence from SCR retrofits on eastern EGUs (see **Appendix A for "EGUs less than 0.06 lb/mmBtu in 2009"**) clearly indicates that SCR can achieve 0.05 lb/mmBtu or lower on an annual basis. For example, we found eight dry-bottom, wall-fired boilers operating at or below 0.05 lb/mmBtu in 2009. We also looked at monthly data for 28 EGUs with SCR's operating at or below 0.05 lb/mmBtu on an annual average (see **Appendix A for "2009 monthly emissions"**) and found that, of the 228 months of data, 214 were at or below 0.06 lb/mmBtu. For dry-bottom, wall-fired EGUs, we found that 73 of 77 months were at or below 0.06 lb/mmBtu. We conclude that SCR can achieve 0.05 lb/mmBtu on an annual basis and 0.06 lb/mmBtu on a 30-day rolling average basis.

It is generally assumed that SCR can achieve at least 90% NO_X reduction,[25] and we have presented evidence demonstrating that SCR can achieve 0.05 lb/mmBtu (or lower) on similar wall-fired boilers. For example, Tri-State Generation has submitted analyses[26] of application of SCR at its Craig Colorado station which is based upon an assumption that SCR can achieve 0.05 lb/mmBtu. We also note that Salt River Project (SRP) assumed that addition of SCR to the Navajo Generating Station[27] could achieve 0.05 lb/mmBtu on an annual basis. The combination of the real-world examples we have previously presented plus the assumptions by Tri-State and SRP should provide sufficient weight-of-evidence for NDEQ to conclude that SCR can reasonably be expected to achieve 0.05 lb/mmBtu (or better) on an annual basis.

Step 4: Evaluate Impacts and Document Results.

<u>NPPD's SCR costs are overestimated.</u> Table 4.a (below) uses company data and estimates that the combination of LNB/OFA+SCR would cost about $2,300/ton to reduce NO_X emissions to 0.08 lb/mmBtu on an annual average basis.

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[23] Minnesota Power Taconite Harbor BART analysis.

[24] Babcock & Wilcox presentation to Minnesota Pollution Control Agency.

[25] Tri-State's Exhibit #20 also assumed 90% NO_X removal.

[26] Exhibit 16 - Craig Stations 1, 2, and 3 November 2010 Black & Veatch Report, Tables 2-1, 2-1, 4-6,4-8, 7-7, 7-8, "Selective Catalytic Reduction System"

[27] Slide 36 of "***Navajo Generating Station Preliminary Capital Cost Estimate***" prepared by Sargent & Lundy and presented by Salt River Project to the Environmental Protection Agency – July 20, 2010.

Table 4.a. Nebraska Public Power--Gerald Gentleman—NPPD estimates **LNB+SCR burning PRB sub-bituminous**

Unit	#1	Source	#2
Rating (MW Net) each	665	company report	700
Rating (mmBtu/hr)	7,538	company report	7,538
Future Uncontrolled Emissions (tpy)	15,122	company report	15,122
Controlled Emissions (lb/mmBtu)	0.08	company report	0.08
Overall Control Efficiency (FGD)	83%	calculated	75%
Emission Reductions (tpy)	12,463	company report	12,463
Capital Cost	$ 257,540,500	company report	$ 257,540,500
Capital Cost ($/kW)	$ 387	calculated	$ 368
Annualized Cost	$ 28,625,500	company report	$ 28,625,500
Cost-Effectiveness ($/ton)	$ 2,297	company report	$ 2,297

SCR Cost Estimation Methods

The SCR cost estimates submitted by NPPD are severely lacking in the types of specific information needed to give them credibility. Although there are several methods for estimating SCR costs, our experience leads us to believe that no one method is perfect and that the costing methods need to be tempered by real-world data. An excellent example of a SCR retrofit cost analysis was prepared for the Navajo Generating Station (NGS) and is being provided separately (in **Appendix B. "SCR Costs"**). The NGS analysis contains the type of vendor estimates and detailed engineering analyses recommended by the BART Guidelines and necessary to arrive at a reasonable and informed estimate of site-specific costs. In the absence of such a comprehensive analysis, the BART Guidelines recommend use of the EPA Control Cost Manual.

"Real-World" SCR Capital Costs

Real-world, utility industry-generated evidence that NPPD has overestimated its SCR costs can be found in a June 2009 article in "Power" magazine:[28]

"One more current data set is the historic capital costs reported by AEP averaged over several years and dozens of completed projects. For example, AEP reports that their historic average capital costs for SCR systems are $162/kW for 85% to 93% NO_X removal..."

"...historical data finds the installed cost of an SCR system of the 700MW-class as approximately $125/kW over 22 units with a maximum reported cost of $221/kW in 2004 dollars. This data was reported prior to the dramatic increase in commodity prices of 14% per year average experienced from 2004 to 2006 (from the FGD survey results). Applying those annual increases to the 2004 estimates for three years (from the date of

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[28] June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO2 and NOx Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier. http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/

the survey to the end of 2007) produces an average SCR system installed cost of $185/kW…"

"Overall, costs were reported to be in the $100 to $200/kW range for the majority of the systems, with only three reported installations exceeding $200/kW."

Five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs, or the costs actually incurred by owners, expressed in dollars per kilowatt. These actual costs are generally lower than estimated by NPPD.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $106 to $213/kW, converted to 2007 dollars.[29] Costs are escalated through using the CEPCI.

The second survey of 40 installations at 24 stations reported a cost range of $76 to $242/kW, converted to 2007 dollars.[30]

The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, or 39% of installed SCR systems in the U.S. This study reported a cost range of $118/kW to $261/kW, converted to 2007 dollars.[31]

A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $180/kW to $202/kW, converted to 2007 dollars.[32]

A fifth summary study, focused on recent applications that become operational in 2006 or were scheduled to start up in 2007 or 2008, reported costs in excess of $200/kW on a routine basis, with the highest application slated for startup in 2009 at $300/kW.[33]

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29 Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. Ex. 2. The reported range of $80 to $160/kW $123 - $246/kW was converted to 2008 dollars ($116 - $233/kW) using the ratio of CEPCI in 2008 to 2002: 575.4/395.6.

30 J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Ex. 3; Jerry Burkett, Readers Talk Back, Power, August 2004, Ex. 4. The reported range of $56/kW - $185/kW was converted to 2008 dollars ($83 - $265/kw) using the ratio of CEPCI for 2008 to 1999 (575.4/.390.6) for lower end of the range and 2008 to 2003 (575.4/401.7) for upper end of range, based on Figure 3.

31 M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Ex. 5. The reported range of $100 - $221/kW was converted to 2008 dollars ($130 - $286/kW) using the ratio of CEPCI for 2008 to 2004: 575.4/444, 2.
http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

32 PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005, Ex. 6. The reported range of $160 - $180/kW) was converted to 2008 dollars ($197 - $221/kW) using the ratio of CEPCI for 2008 to 2005 (575.4/468.2).

33 J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Ex. 1).

EPA's Region 8 Office has compiled a graphic presentation of SCR capital costs adjusted to 2009 dollars—please see **Appendix B for "SCR References"**. The EPA data confirm that SCR capital costs typically range from $73 – $243/kW.

A graphic illustration of a "real-world" retrofit was presented by Burns & McDonnell at the 2010 Power Plant MegaSymposium and is provided in **Appendix B in the "Boswell retrofit" files**. Despite the limited space and other obstacles, the SCR installation cost $205/kW.[34] It should also be noted that the Boswell Unit 3 retrofit was designed to meet 0.05 lb/mmBtu. Burns & McDonnell reported that performance tests showed that, "Average NOx emissions at the outlet of the SCR reactor were 0.029 lb/mmBtu, which is below the design emission rate for the SCR system (0.05 lb/mmBtu)."

Thus, the overall range for these industry studies is $50/kW to $300/kW. The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost $265/kW,[35] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[36] only cost $251/kW in 2007 dollars.[37]

We reviewed NPPD's Appendix C[38] to determine the costs it had specifically assigned to SCR and derived Table 4b. below:

Table 4.b SCR at 0.08 lb/mmBtu

SCR Cost Components	NPPD*	NPS**
Direct Capital Cost	$ 268,199,000	$ 268,199,000
Indirect	$ 35,212,000	$ 53,639,800
Escalation	$ 60,482,000	
Sales/Use Tax	$ 5,589,000	$ 5,589,000
Contingency	$ 72,779,000	$ 61,685,770
AFUDC	$ 41,150,000	
Total Capital Cost (w/ fan sized for SCR only)	$ 478,151,000	$ 389,113,570
Total Capital Cost/kW	$ 350	$ 285
Capital Recovery Factor		0.0944
Levelized Capital Cost (w/ fan sized for SCR only)	$ 38,755,000	$ 36,729,568
Levelized O&M Cost	$ 14,515,000	$ 14,515,000
Levelized Outage Cost	$ 1,021,000	$ 1,021,000
Total Levelized Capital, Outage and O&M Cost	$ 54,291,000	$ 52,265,568

[34] Minnesota Power's Environmental Improvement Plan submitted to the MN PUC 10/27/06, Docket #E015/M-06-1501. LNB+OFA+SCR TCI = $77 million in 2006 $ on 375 (gross) MW Unit #3.

[35] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Ex. 7. The unit cost: ($325,000,000/1,120,000 kW) (608.8/395.6) = $290/kW. http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

[36] Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

[37] McIlvaine, NOX Market Update, August 2004, Ex. 9. SCR was retrofit on Gibson Units 2-4 in 2002 and 2003 at $179/kW. Assuming 2002 dollars, this escalates to ($179/kW) (608.8/395.6) = $275.5/kW. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

[38] SCR AND ID FAN & AUXILIARY POWER CONCEPTUAL DESIGN COSTS

Tons NOx removed		9,970		9,970
SCR cost-effectiveness ($/ton)	$	5,445	$	5,242

*SCR AND ID FAN & AUXILIARY POWER CONCEPTUAL DESIGN COSTS
**Based upon OAQPS Control Cost Manual

NPPD's $350/kW capital cost is much higher than the $250 - $300/kW range estimated for SCR at this facility by applying recent industry cost data.[39] It is likely that the capital cost estimates from NPPD were the highly influenced by the improper inclusion of over $60 million in "Escalation" costs and over $41 million in AFUDC costs. We also question a "Contingency" cost of over $72 million (27%) of a $268 million total; this is higher than the 23% contingency expense estimated by the Cost Manual. If the $89 million in these excess costs is eliminated from the NPPD estimate, the resulting $285/kW becomes more consistent with industry data. Finally, by choosing the most costly alternative for supplying ammonia to the SCR, the use of urea with a conversion plant, NPPD has further increased costs above the typical industry SCR installation.

Because the NPPD capital costs estimates were higher than we expected, we applied the Cost Manual methods to the NPPD cost analyses.

EPA Control Cost Manual

We have been working with an Excel workbook we derived from the SCR cost estimation method presented by EPA's Office of Air Quality Planning and Standards Control Cost Manual (Cost Manual). Based upon the industry data cited above, we now believe that the Cost Manual method tends to underestimate the Direct Capital Cost (DCC) component of the SCR cost estimate. Because the Total Capital Investment (TCI) component is directly proportional to the DCC in the Cost Manual method, a straightforward application of the Cost Manual method usually results in TCI costs lower than what we would expect from the real-world industry data presented above. Therefore, we have been developing a way to modify the Cost Manual method to provide TCI estimates more consistent with industry data. First, we adjust the DCC from the Cost Manual's 1998 baseline to current (2009) cost using the Chemical Engineering Plant Cost Index (CEPCI ratio = 1.34) to adjust costs for inflation. Next we use the DCC presented by the source ($135 million for each EGU) and apply the Cost Manual ratios for Indirect Installation (20%) and Contingency (5% + 18%) costs to the DCC to estimate TCI. If the resulting TCI $189 million each EGU) expressed in $/kW ($284/kW) is within the expected range, we carry that estimate through the remainder of the cost estimation process. (If this TCI estimate is outside the expected range, we can override the TCI calculation by inserting our best estimate (in $/kW) based upon the size of the EGU and the degree of retrofit difficulty.) **Please see the individual source analyses for specific details of how we apply this method.**

Annual SCR Costs

The Direct Annual Cost (DAC) component of the process is also important because it

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[39] J.E. Chichanowicz Report "Current Capital Cost and Cost Effectiveness," January 2010

represents a significant portion of the Total Annual Cost. The methods presented by the Cost Manual for estimating DAC appear to be straight-forward and should accurately represent annual costs with no need for adjustment. However, the BART analyses presented by NPPD show a consistent significant overestimation of DAC.

We applied the procedures described in Section 4, Chapter 2 of the Cost Manual to the GGS boilers (Tables 5.a and 5.b).[40] Because modern SCR systems are typically designed to achieve 90+% NO_x reductions, we used 0.05 lb/mmBtu as our target. Except for the Annual Maintenance Costs, all other O&M cost estimates produced by NPPD were significantly higher than estimated by a direct application of the Cost Manual, even though we estimated a greater amount of NO_X removal which should have led to higher operating costs. Due to a lack of supporting information, we were unable to determine the reasons for NPPD's higher cost estimates. We estimated a Total Annual Cost of $24.5 million for GGS Unit 1, and produced cost-effectiveness estimates of $2,000/ton.

Table 5.a Annual Costs for SCR at 0.05 lb/mmBtu	Gerald Gentleman Station Unit 1		NPPD/NPS
	NPS	NPPD	
Annual Maintenance Cost =	$ 2,835,007	$ 733,000.00	26%
Annual Reagent Cost =	$ 824,401	$ 1,751,000	212%
Annual Electricity Cost =	$ 762,722	$ 2,412,000	316%
Annual Catalyst Cost =	$ 732,419	$ 2,329,000	318%
DAC =	$ 5,154,549	$ 7,225,000	140%
Indirect Annual Cost =	$ 17,840,306	$ 19,128,000	107%
SCR Total Annual Cost =	$ 22,994,855	$ 27,145,500	118%
CC+SCR Total Annual Cost =	$ 24,474,855	$ 28,625,500	117%
NOx Removed by SCR =	5,303	4,626	87%
Total NOx Removed =	12,160	12,463	102%
SCR Cost effectiveness =	$ 4,336	$ 5,445	126%
Total Cost effectiveness =	$ 2,013	$ 2,297	114%

Table 5.b. Annual Costs for SCR at 0.05 lb/mmBtu	Gerald Gentleman Station Unit 2		NPPD/NPS
	NPS	NPPD	
Annual Maintenance Cost =	$ 2,835,000	$ 733,000.00	26%
Annual Reagent Cost =	$ 800,657	$ 1,776,000	222%
Annual Electricity Cost =	$ 740,755	$ 2,412,000	326%
Annual Catalyst Cost =	$ 732,419	$ 2,367,000	323%
DAC =	$ 5,108,831	$ 7,288,000	143%
Indirect Annual Cost =	$ 17,840,263	$ 19,627,000	110%
SCR Total Annual Cost =	$ 22,949,094	$ 27,145,500	118%
CC+SCR Total Annual Cost =	$ 24,429,094	$ 28,625,500	117%
NOx Removed by SCR =	5,150	4,692	91%
Total NOx Removed =	8,318	12,463	150%
SCR Cost effectiveness =	$ 4,456	$ 5,445	122%
Total Cost effectiveness =	$ 2,937	$ 2,297	78%

[40] Our calculations are contained in the attached Excel workbook and in Appendix B.

We estimated a Total Annual Cost of $24.4 million for GGS Unit 2, and produced cost-effectiveness estimates of $2,900/ton.[41]

Step 5: Evaluate Visibility Impacts.

NDEQ estimates that reducing NO_X emissions to 0.08 lb/mmBtu would improve visibility at Badlands NP (the only Class I area for which improvements was provided) by 1.152 dV, but we did not have sufficient data to evaluate the cumulative benefits of improving visibility at the other Class I areas. If the SCR achieved the lower emission rate that we believe is reasonable, then the visibility benefits would increase.

BART Determination for NO_X

Quoting NDEQ: LNB/OFA technology is a feasible NO_x retrofit technology that could be implemented on GGS Units 1 and 2.

The average cost effectiveness of this control technology is $198 per ton NO_x removed. Over the three years of meteorology modeled, the average incremental visibility impairment improvement cost is $4,475,825 per year per change in deciview impact.

Utilizing SCR technology is also feasible only if LNB/OFA is utilized. The incremental cost effectiveness (incremental cost SCR) is $5,445 per ton NO_x removed, over 25 times the amount of LNB/OFA alone. Over the three years of meteorology modeled, the incremental visibility impairment improvement cost of adding SCR is $111,993,640 per year per change in deciview impact. The average incremental improvement in visibility for the addition of SCR is less than 0.5 dV and improvement would be seen on an average of 7.3 days per year.

The NDEQ determined that the incremental cost for the addition of SCR is excessive and that LNB/OFA would be required for BART.

Therefore BART for GGS Units 1 and 2 shall be the installation of LNB/OFA with an emission limitation of 0.23 lb NOx/MMBtu.

<u>NPS NO_X BART Conclusions:</u>

We have presented information showing that several EGUs are operating at much lower NO_X rates than evaluated by NDEQ. NDEQ should evaluate NO_X rates that reflect the capabilities of SCR systems.

Use of EPA guidance and industry data results in capital and O&M cost estimates that are significantly lower than those presented by NPPD. NDEQ improperly rejected Selective Catalytic Reduction (SCR) as too expensive on an incremental cost-per-deciview-improvement ($/dv) basis. NDEQ began its cost-effectiveness analysis by estimating the average costs of combustion controls:

[41] The higher Total Cost Effectiveness for LNB/OFA+SCR on GGS #2 is primarily due to its inherently lower uncontrolled NO_X emissions and the higher cost/ton of the LNB/OFA to reduce NO_X emissions to the presumptive BART level.

> The total annualized cost associated with the installation of LNB/OFA is $2,960,000. The cost effectiveness of LNB/OFA is $198 per ton NOx removed ($2,960,000 / 14,956 tons NOx removed).

and then the combination of combustion control plus SCR:

> The total annualized cost associated with the installation of LNB/OFA and SCR is $57,251,000. The cost effectiveness of LNB/OFA and SCR is $2,297 per ton NOx removed ($57,251,000 / 24,926 tons NOx removed).

in accordance with its proper understanding of the cost-effectiveness of such a combination:

> Although SCR is a feasible control technology, **it would be most practical to install SCR in combination with combustion controls**. This is because if NOx formation was not reduced upstream of the SCR system, the amount of catalyst required would be higher, subjecting more catalyst to degradation. The amount of ammonia required would also be higher, increasing the capital and O&M costs of SCR significantly. Also, reagent costs would be significantly higher if LNB/OFA were not used to minimize NOx emissions before treatment with the SCR system. Therefore, the cost associated with installing LNB/OFA is linked to this control technology throughout the analysis.

NDEQ should have stopped at that point. However, NDEQ then contradicted its proper assessment of the combination of combustion controls plus SCR and created an incremental cost for a "straw man" strategy that it had already deemed "impractical":

> The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option. The incremental cost analysis of installing LNB/OFA and SCR as opposed to LNB/OFA alone is $5,445 ([$57,251,000 - $2,960,000] / [24,926 – 14,956]).

NDEQ should have relied upon its good judgment that "it would be most practical to install SCR in combination with combustion controls" and based its decision upon the outcome of that analysis.[42]

Use of EPA guidance and data result in cost-effectiveness values for combustion modifications plus SCR of $2,000 - $3,000/ton. This cost-effectiveness appears reasonable, given the magnitude and extent of GGS' impacts upon visibility.

NDEQ should re-do its SCR analysis in the format presented by the OAQPS Control Cost Manual[43] and model the effects on all Class I areas of reducing NO_x to not greater than 0.07 lb/mmBtu and provide the information to develop the "fifth factor" in the BART process.

[42] It should be noted that the combustion controls currently present on GGS #1 did not exist at the time the BART Guidelines were finalized, and thus cannot be separated from the LNB/OFA+SCR combination endorsed by NDEQ.

[43] It would be very helpful if NPPD would provide vendor quotes and supporting documentation for major cost items.

MEMORANDUM

To: Tim Allen; USFWS, NWR System, Branch of Air Quality

From: Greg Wingfield, Mike George; USFWS NEFO

RE: Nebraska Draft Regional Haze State Implementation Plan

Date: December 22, 2010

This responds to your request for review of Nebraska's Draft Regional Haze State Implementation Plan. In your e-mail of December 6, 2010, you specifically asked for our opinion on: (a) "the merits of [NDEQ] arguments" and (b) "are there options for utilizing the water and still maintaining ESA protection".

The arguments given by NDEQ have some merit. However, the Platte River Recovery Implementation Program (PRRIP) inherently provides options to offset consumptive use that results in depletions to the river and jeopardizes endangered species. Additionally, it appears much of the information provided in NDEQ's plan represents a worst-case scenario when describing offsets to water used by the Nebraska Public Power District (NPPD). While not inaccurate, the information tends to overstate implications of any new water use by NPPD.

The statements in the plan regarding Nebraska state water law, the Cooperative Agreement that resulted in the PRRIP, and the ensuing commitments of the State of Nebraska via its participation in the PRRIP appear correct. The PRRIP was developed knowing that it would be untenable to prevent all new water uses. Thus, the approach was to devise ways to provide for the water-dependent needs of listed species while accommodating new uses. The method of accommodating uses is complex and detailed; methods are delineated in the respective states' and federal agencies' New Depletions Plans. In essence, there is an obligation to provide offsets for water uses above and beyond a 1997 baseline use. For your reference we are attaching PRRIP document language pertaining to accommodating new uses from the PRRIP's purpose statement (attachment A, item 4 in bold) and from a description of the elements for overall PRRIP implementation (attachment A, item 3 in bold).

Basically, the draft haze plan represents Nebraska's water resources expert, the Nebraska Department of Water Resources (NDWR), advising its sister agency, NDEQ, that the environmental impacts to ESA-listed species from the act of mitigating environment impacts to air quality are onerous. Specifically, NDNR has indicated that "placing this additional demand on the basin jeopardizes Nebraska's ability to meet commitments made to other states and the federal government ..." (page 53). Achieving the ESA recovery objectives of the PRRIP will be a challenging endeavor and it is in the Service's interests to see Nebraska succeed. Thus we understand the basis of their position and advice to NDEQ (i.e. our conclusion that their argument has some merit). However, it appears the figures and calculations used to describe offset needs and compare them to other needs/obligations may portray a worst-case scenario.

The draft haze plan omits several important considerations. First, offset needs for the PRRIP and IMPs may be able to be met concurrently or synergistically; the plan only hints at this by stating that these needs "may not necessarily be mutually exclusive". The plan fails to note that the majority of the remaining 50,000-70,000 AF of PRRIP 1st Increment water objective will likely be met by re-timing (re-regulating) existing water supply from times when target flows are exceeded to times of shortage (i.e. not solely by obtaining "new" water via conservation or acquisition of existing water rights). Further, any commitment of the parties to proceed toward obtaining the estimates of water listed for a 2nd and 3rd Increment is speculative, at best. While the Service has calculated an average annual shortage to targets of approximately 430,000 AF, there is no certainty that future PRRIP increments will include an objective to achieve this magnitude of reduction to shortages. If such commitments are made, undoubtedly the three states would each contribute; because the plan is silent on this, one might assume incorrectly that it would only be Nebraska's hardship to find the water.

Also, the example offset-driven acreage retirements provided by Twin Platte NRD likely do not represent the approach NPPD would take. The example uses an array of north/south sections immediately west of GGS so the stream depletion factors (SDF) vary widely (from 15 to 96%) and average 56%. There is no explanation or justification for this. Entities looking either to secure offsets (e.g. Central Platte NRD in their existing water banking program) or secure new supply for river flows (e.g. PRRIP as part of the 50,000-70,000 shortage reduction objective) are targeting irrigated land with higher SDFs. Presumably NPPD would use a similar approach, when possible, resulting in less acreage retired from irrigation. Accordingly, economic impacts from irrigated acreage retirements would be reduced proportionately. Finally, some of the statements about the economic impacts infer that NPPD would acquire the land in fee title, not just the water right for retirement (e.g. the $88,000,000 total cost for land acquisition).

It does not appear the plan has sufficiently considered all potential, feasible sources for this amount of water. You might want to get clarification on whether there are exceptions to the well-drilling moratorium in the Twin Platte NRD. Are there any industrial or commercial large capacity wells that could be acquired as part of the water supply or retired as part of the offsets? Are there potential deep-well ground water sources outside of the hydrologically connected area, but much closer (and much less expensive) than the example source of piping water from the Missouri River that is referenced? It almost seems like the Nebraska parties could be taking the approach of "where there is a will there is a way", similar to how new agricultural, commercial or industrial water users would investigate possible sources to accommodate their needs (e.g. ethanol plants).

In summary, there is no question any new depletions to central Platte River flows would require offsets. Because of this, there is the possibility that accelerating actions to achieve air quality improvements would weaken Nebraska's ability to meet its PRRIP obligations to improve Platte River flows on schedule. But we do not believe that it **automatically** follows that air quality improvements cannot be pursued because Nebraska simply could not do both.

Attachment A

<u>Excerpts from Program document sections on purpose and elements.</u>

PROGRAM PURPOSES

A. The purpose of this Program is to implement certain aspects of the U.S. Fish and Wildlife Service's (FWS') recovery plans for the target species that relate to their associated habitats by providing for the following:

1. securing defined benefits for the target species and their associated habitats to assist in their conservation and recovery through a basin-wide cooperative approach agreed to by the three states and DOI;

2. providing ESA compliance2 for existing and new water related activities3 in the Platte River basin4;

3. helping prevent the need to list more basin associated species pursuant to the ESA;

4. mitigating the adverse impacts of new water related activities on (1) the occurrence of FWS target flows (as described in Section III. E.1.a.) and (2) the effectiveness of the Program in reducing shortages to those flows, such mitigation to occur in the manner and to the extent described in Section III.E.3 and in the approved depletions plans; and

5. establishing and maintaining an organizational structure that will ensure appropriate state and federal government and stakeholder involvement in the implementation of the Program.

PROGRAM ELEMENTS

A. General Description

1. Elements. The Program has three elements: (1) increasing streamflows in the central Platte River during relevant time periods through reregulation and water conservation/supply projects; (2) enhancing, restoring and protecting habitat lands for the target species; and **(3) accommodating new water related activities in a manner consistent with long-term Program goals.**