United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
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IN REPLY REFER TO:

N3615 (2350)

August 3, 2012

Carl Daly
Director, Air Program
Environmental Protection Agency, Region 8
Mailcode 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202-1129

EPA Docket ID: EPA-R08-OAR-2012-0026
EPA–R08–OAR–2011–0400

Dear ~~Mr. Daly~~, Carl

The National Park Service (NPS) has reviewed the Environmental Protection Agency (EPA)'s proposed "Approval and Promulgation of State Implementation Plans; State of Wyoming; Regional Haze Rule Requirements for Mandatory Class I Areas" published in the Federal Register on May 22, 2012, and "Approval, Disapproval and Promulgation of State Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze" published in the Federal Register on June 4, 2012. We previously commented to the State of Wyoming on August 4, 2009 and October 21, 2009 on the proposed state implementation plan and proposed BART determinations.

We commend EPA for considering additional emissions reductions beyond those proposed by Wyoming Department of Environmental Quality (WY DEQ). We have several remaining concerns, however, as detailed below and in the attachments.

Best Available Retrofit Technology (BART) for Sulfur Dioxide (SO_2)

Consistent with the requirements of 40 CFR 51.309(d)(4)(i)-(vi), we agree with EPA Region 8 that the Western Backstop Sulfur Dioxide Trading Program meets the BART requirements for stationary source SO_2 emissions in the participating States of New Mexico, Utah, and Wyoming.

Best Available Retrofit Technology (BART) for Nitrogen Oxides (NO_X)

In our reviews of control options for NOx emissions, we have recommended consistency across the states and EPA regions. In the case of Wyoming, it appears that EPA Region 8 has accepted the cost calculations provided by WY DEQ and the utitilies (Pacificorp and Basin Electric) without conducting independent analyses. As discussed in the enclosures, WY DEQ and the utilities did not follow the EPA Control Cost Manual and overestimated the costs of Selective Catalytic Reduction (SCR). Estimated costs in $/kw are significantly higher than industry data show for actual installations across the country, and WY DEQ and the utilities did not provide data to support these high estimates.

Further, WY DEQ underestimated the efficiency of SCR in reducing emissions. SCR technology is rountinely capable of achieving 90% removal efficiency, yet WY DEQ's proposed annual average emissions limits of 0.07 lb/mmBtu represent a 53-81% removal efficiency. We disagree with EPA Region 8's proposal to accept 0.07 lb/mm Btu for Wyoming when EPA Regions 6 and 9 have proposed SCR at 0.05 lb/mmBtu for facilities in NM and AZ. EPA Region 8 identified 0.05 lb/mm Btu annual average as feasible for SCR in Montana. By underestimating the control efficiency, WY DEQ and EPA have also underestimated the visibility benefits of SCR controls.

While we commend EPA Region 8 for re-modeling Wyoming facilities to investigate the effects of changes in NO_X emissions on visibility, we are concerned that the modeling described in its "Summary of EPA's Additional Visibility Improvement Modeling" deviates significantly from the BART Guidelines.

EPA Region 9 cited the cumulative visibility benefits at several Class I areas in justifying SCR for facilities in Arizona. EPA Regions 1, 2, 6, 7, and 8 have recommended that states consider cumulative benefits at impacted Class I areas in evaluating BART controls. However, even though WY DEQ reported impacts at multiple Class I areas, EPA Region 8 considered visibility impact for only the single most-impacted Class I area in its review of WY DEQ's determinations. Thus EPA Region 8 underestimated the benefits of SCR controls.

EPA Region 8 appears to have overestimated the efficiency of Selective NonCatalytic Reduction (SNCR) technology. EPA's Clean Air Market data does not show any current SNCR installation achieving an emissions limit of 0.12 lb/mmBtu. By overestimating the efficiency of SNCR and underestimating the efficiency of SCR, EPA has recommended SNCR as BART where we would recommend SCR.

WY DEQ and EPA Region 8 have placed undue weight on incremental costs and incremental benefits. WY DEQ and EPA Region 8 have essentially based their BART and Reasonable Progress determinations on incremental costs and incremental benefits. If EPA is going to compare costs and visibility benefits, we request that it do so in a transparent and objective manner, and state the criteria for acceptance or rejection of a control strategy.

We believe that consistent with other western states, SCR with a rolling 30-day emissions limit of 0.06 lb/mmBtu should be determined to be BART for the WY facilities: Jim Bridgers Units 1-4, Dave Johnston Units 3 and 4, Laramie River Units 1-3, Naughton Units 1-3, and Wyodak and Reasonable Progress for Dave Johnston Units 1 and 2.

We appreciate the opportunity to work closely with EPA Region 8 and WY DEQ to improve visibility in our Class I areas. For further information regarding our comments, please contact Don Shepherd at (303) 969-2075.

Sincerely,

Susan Johnson
Chief, Policy, Planning and Permit Review Branch

enclosure

cc:
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National Park Service (NPS) General Comments on EPA Region 8's proposed Best Available Retrofit Technology (BART) and Reasonable Progress Determinations For Wyoming's Regional Haze Plan August 3, 2012

WY DEQ has underestimated the ability of Selective Catalytic Reduction (SCR) to reduce emissions. In our August 2009 comments to WY DEQ, we advised that:

> Our review of operating data suggests that…a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates.

However, in estimating the annual cost-effectiveness of the SCR option, WY DEQ assumed 0.07 lb/mmBtu on an annual average basis. Based on the NO_X emission rates predicted for the combustion control options, SCR emissions at 0.07 lb/mmBtu represent SCR control efficiencies of only 53% - 81% as opposed to the generally-accepted 90%. WY DEQ has not provided any documentation or justification to support the higher emission rates used in their analyses. In other recent BART actions, EPA has determined that SCR can achieve 0.05 lb/mmBtu on an annual basis. Such underestimates of SCR effectiveness in Wyoming adversely change the cost-benefit analyses and are inconsistent with other EPA analyses discussed below.

In evaluating the boilers at the Colstrip power plant in Montana, EPA R8 stated that "an annual emission rate of 0.05 lb/MMBtu is achievable with SCR."

Also, EPA Region 5 advised Minnesota that:

> We believe that the available evidence indicates that Xcel Energy's Sherburne County facility (Sherco) should add selective catalytic reduction (SCR) to the recommended nitrogen oxides (NO_X) combustion controls. We are basing this on calculations we have performed evaluating SCR at emission levels of 0.05 pounds per million British Thermal Units (lb/MMbtu) and 0.08 lb/MMBtu. Both of which are considered cost-effective. We chose to evaluate these two emission levels because you assumed a 0.08 lb/MMBTU level in your analyses and because we believe that the lower limit of 0.05 lb/MMBTU is generally achievable by this control technology. [1]

Further, EPA Region 6's (R6) evaluation of NO_X BART for the San Juan Generating Station (SJGS) (included in Appendix A) provides a good example of a thorough technical analysis**.** [2] In making its final determination, EPA R6 stated:

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[1] June 6, 2011 letter from Doug Aburano, Chief, Control Strategies Section, EPA Region 5 to John Seltz, Chief, Air Assessment Section, Minnesota Pollution Control Agency

[2] **San Juan Generating Station Source Description:** The San Juan Generating Station (SJGS) consists of four coal-fired electric generating units (EGUs) and associated support facilities. Units 1 and 2 are Foster Wheeler subcritical, dry-bottom, wall-fired boilers that operate in a forced draft mode and have a unit capacity of 360 and 350 MW, respectively. Units 3 and 4 are B&W subcritical, dry-bottom, opposed wall-fired boilers that operate in a forced draft mode, and each has a unit capacity of 544 MW. Consent Decree: On March 5, 2005, Public Service of New Mexico (PNM) entered into a consent decree (CD) with the Grand Canyon Trust, the Sierra Club, and the New Mexico Environment Department to settle alleged violations of the Clean Air Act. The CD required PNM to meet a

> For the reasons discussed in our proposal (76 FR 491), and in other responses to comments, we have concluded that BART for the SJGS is an emission limit of 0.05 lbs/MMBtu, based on a 30 BOD[3] average, more stringent than the levels achievable by the SNCR technology recommended by the State.

Finally, EPA Region 9's current proposal regarding Arizona's RH SIP includes this evaluation of SCR performance:[4]

> In particular, we find that ADEQ did not adequately support its estimate of SCR control effectiveness. SCR, as an add-on control technology, can be installed by itself as a standalone option or in conjunction with burner upgrades. In cases where units can be upgraded with combustion control technology such as low-NOx burners, SCR is commonly installed as an addon post-combustion control. When evaluating control options with a range of emission performance levels, the BART Guidelines indicate that "in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving." Existing vendor literature and technical studies indicate that SCR systems are capable of achieving a 0.05 lb/MMBtu emission rate (approximately 80-90% control efficiency) and that this emission rate can be achieved on a retrofit basis, particularly when combined with combustion control technology such as LNB.[5]
>
> In the absence of source-specific considerations warranting a less stringent control level, we presume that an emissions limit of 0.05 lb/MMBtu is achievable by these units through the use of SCR in addition to advanced combustion controls.

We agree with EPA that "an annual emission rate of 0.05 lb/MMBtu is achievable with SCR."

WY DEQ has overestimated the cost of SCR. WY DEQ has not provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and WY DEQ did not use the EPA OAQPS Control Cost Manual (CCM), as recommended by the BART Guidelines. For example, the cost estimates used by WY DEQ and EPA R8 contained Allowance for Funds Utilized During Construction, which is not allowed by the CCM and has been rejected by EPA R8 in other analyses. As a result, total capital costs estimated by WY DEQ for SCR exceeded $300/kW at ten of the 15 EGUs evaluated.

<u>"Real-World" SCR Capital Costs</u>

0.30 lb/mmBtu emission rate for NO_X (daily rolling, thirty day average), for each of Units 1, 2, 3, and 4. As a result, PNM has installed new LNB with OFA ports and a neural network system to reduce NO_X emissions.

[3] Boiler Operating Days

[4] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 51 [EPA-R09-OAR-2012-0021] Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans AGENCY: Environmental Protection Agency (EPA) ACTION: Proposed rule.

[5] See Docket Items G-04, "Emissions Control: Cost-Effective Layered Technology for Ultra-Low NOx Control" (2007), Docket Item G-05 "What's New in SCRs" (2006), and Docket Item G-06 "Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers" (2005)

Real-world, utility-industry-generated data on SCR costs can be found in a report[6] prepared for the Utility Air Regulatory Group and also in a June 2009 article in "Power" magazine:[7]

> 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 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 all at or lower than $300/kW:

- The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $111 to $223/kW, converted to 2010 dollars.[8]
- The second survey of 40 installations at 24 stations reported a cost range of $79 to $253/kW, converted to 2010 dollars.[9]
- 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 $124/kW to $274/kW, converted to 2010 dollars.[10]
- A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $188/kW to $212/kW, converted to 2010 dollars.[11]

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[6] OVERVIEW OF INFORMATION ON PROJECTED CONTROL TECHNOLOGY COSTS AND PERFORMANCE AS DEVELOPED FOR EPA'S INTEGRATED PLANNING MODEL (IPM) October 15, 2010 Prepared by J. Edward Cichanowicz

[7] 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/

[8] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. The reported range of $80 to $160/kW $123 - $246/kW in 2002 $ was converted to 2010$ using the CEPCI ratio.

[9] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Ex. 3; Jerry Burkett, Readers Talk Back, Power, August 2004. The reported range of $56/kW - $185/kW in 1999$ - 2003$ was converted to 2010$ using the CEPCI ratio, based on Figure 3.

[10] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. The reported range of $100 - $221/kW was converted to 2010$ using the CEPCI ratio. http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

- 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.[12]

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, that SCR installation cost \$205/kW.[13] It should also be noted that the Boswell #3 retrofit was designed to meet 0.05 lb/mmBtu. Burns & Mc Donnell 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 in North Carolina, reported to cost \$265/kW,[14] or Cinergy's Gibson Units 2-4 in Indiana. 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,[15] cost \$249/kW in 2010 dollars.[16]
EPA R8 has compiled a graphic presentation of SCR capital costs adjusted to 2009 dollars—please see Appendix B for "SCR References Colorado". The EPA data confirm that SCR capital costs typically range from \$73 – \$243/kW. WY DEQ has not demonstrated unique features for the Wyoming EGUs that would justify cost estimates so much higher than the range for the industry.

In conducting our cost analyses of SCR, we used an approach similar to that used by EPA R8 in its evaluation of SCR on the Colstrip power plant—following is an excerpt from EPA R8's proposed Montana FIP:

> We relied on a number of resources to assess the cost of compliance for the control technologies under consideration. In accordance with the BART Guidelines (70 FR 39166), and in order to maintain and improve consistency, in all cases we sought to align our cost methodologies with the EPA CCM.[17] However, to ensure that our methods also reflect the most recent cost levels seen in the marketplace, we also relied on a set of cost

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[11] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005. The reported range of \$160 - \$180/kW was converted to 2010\$ using the CEPCI ratio.
[12] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1.
[13] 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.
[14] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002. 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/
[15] Standing on the Shoulder of Giants, Modern Power Systems, July 2002
[16] 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 \$249/kW in 2010\$ using the CEPCI ratio. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm
[17] EPA Control Cost Manual Sixth Edition, January 2002, EPA 452/B–02–001

> calculations developed for the Integrated Planning Model (IPM) version 4.10.[18] These IPM cost calculations are based on databases of actual control project costs and account for project specifics such as coal type, boiler type, and reduction efficiency. The IPM cost calculations reflect the recent increase in costs in the five years proceeding 2009 that is largely attributed to international competition. Finally, our costs were also informed by cost analyses submitted by the sources, including in some cases vendor data.
>
> Annualization of capital investments was achieved using the CRF [Capital Recovery Factor] as described in the CCM.[19] Unless noted otherwise, the CRF was computed using an economic lifetime of 20 years and an annual interest rate of 7%.[20] All costs presented in this proposal have been adjusted to 2010 dollars using the Chemical Engineering Plant Cost Index (CEPCI).[21]

We used EPA's IPM model to estimate Direct Capital Cost (DCC) and adjusted for inflation to 2010$.We then applied the CCM factors (totaling 141%) for Indirect Capital Cost to estimate a Total Capital Investment (TCI). Next, we applied the CCM methods for estimating Direct and Indirect Annual Costs to the TCI and arrived at a Total Annual Cost.

EPA R8 has incorrectly estimated visibility improvement from all NO_X control options. While we commend EPA R8 for re-modeling Wyoming EGUs to investigate the effects of changes in NO_X emissions on visibility, we are concerned that the modeling described in its "Summary of EPA's Additional Visibility Improvement Modeling" deviates significantly from the BART Guidelines. EPA R8 states:

> EPA performed additional modeling of NOx control scenarios for both BART and reasonable progress sources. For baseline emissions, the BART Guidelines recommend that states use the maximum 24-hour average actual emission rate for the meteorological period being modeled. The visibility modeling performed by PacifiCorp, and subsequently submitted by the state, deviates from this guidance by using the permit limit emission rates and maximum rated heat input to derive the modeled emission rates instead of the actual maximum 24-hour average. The visibility modeling performed by Basin Electric, and subsequently submitted by the state, also deviates from this guidance by using a baseline hourly emission rates derived from actual annual average heat input (MMBtu) and actual annual average emission rates (lb/MMBtu) from 2001-2003 continuous emissions monitoring (CEM) data. For consistency, EPA's additional modeling to ascertain visibility improvements from individual NOx controls used the state's baseline emission rates for the PacifiCorp sites and Basin Electric's Laramie River Station. All other aspects of EPA's additional visibility modeling followed the recommendations made in the BART Guidelines.

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[18] Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, August 2010, EPA #430R10010
[19] Section 1, Chapter 2, page 2-21.
[20] Office of Management and Budget, Circular A-4, Regulatory Analysis, http://www.whitehouse.gov/omb/circulars_a004_a-4/.
[21] Chemical Engineering Magazine, p. 56, August 2011. (*http://www.che.com*).

As a result, the changes in hourly NO_X emission rates modeled by EPA R8 did not correlate with actual hourly emissions and the annual emission percentage reduction estimates. This problem was most pronounced for the Laramie River Power Plant where EPA R8 modeled tons/yr instead of lb/hr.

We reviewed the Wyoming SIP Regional Haze modeling files provided to us by EPA R8. We have several concerns with the modeling that was performed for EPA R8 by its contractor. An older version of the CALPUFF modeling suite was used (CALPUFF model of March 2006 vintage and the CALPOST model of April 2006 vintage.) These older versions pre-date the latest Model Change Bulletin (MCB-D) of June 23, 2007. Since the analysis for the five Wyoming power plants was performed in February thru April 2012, we question why the older version was used and not the current CALPUFF 5.8 version which was approved as the guideline version in June of 2007. We do not recommend use of the older versions of CALPUFF and CALPOST.

EPA R8 has underestimated visibility improvement from SCR. We are concerned about the emissions modeled by EPA R8 as presented in the "Summary of EPA's Additional Visibility Improvement Modeling." For example, sulfuric acid mist (H_2SO_4) emissions from each PacifiCorp unit are assumed to double from the baseline and control scenarios that do not include SCR versus scenarios with SCR. The only explanation provided by EPA R8 is that "the emission rate for …total sulfate rates were increased to account for the additional production that results from SCR controls." Once again, EPA's approach in Wyoming is not consistent with its approach elsewhere. For example, in its modeling analysis of addition of SCR at Colstrip Units 1 and 2 in Montana, EPA R8 assumed no additional sulfate emissions from the addition of SCR.

In its analysis of the San Juan Generating Station in NM, EPA R6 stated:

> EPA used calculations by the NPS submitted to NMED in response to the proposed Regional Haze SIP and later revised that differed from certain assumptions and methodology used by NMED for SJGS to calculate the sulfuric acid emissions. In particular, the amount of sulfuric acid produced during combustion, the rate of SO2 to SO3 oxidation from the SCR catalyst and the amount of sulfuric acid that penetrates through (or is lost to) the downstream equipment differed from SJGS and NMED's. Sulfuric acid emissions from power plants were calculated by NPS by estimating the amount of H2SO4 produced and the amount of H2SO4 removed by control equipment using information from the Electric Power Research Institute (EPRI). These calculations rely on assumed values for the amount of fuel sulfur converted to SO2, the amount of SO2 oxidized to SO3, and the amount of H2SO4 lost to (or mitigated by) the air preheater and applicable control equipment, such as baghouses, and FGDs. Baseline and post-control estimates of H2SO4 from SJGS are based on the best current information available from EPRI and coal properties (Table 6-1).[22]

In its analysis of the Reid Gardner Generating Station in NV, EPA R9 stated:

[22] Technical Support Document Visibility Modeling for BART Determination: San Juan Generating Station, New Mexico, Prepared by: U.S. Environmental Protection Agency, Region 6, Michael Feldman Erik Snyder

> For the cases modeled in our analysis, we accounted for two mechanisms of sulfur acid manufacture: (1) combustion from fuel and (2) production from use of SCR catalyst. These emissions were calculated using either AP-42 emission factor data or the Electric Power Research Institute (EPRI) document "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants."[23]

Because H_2SO_4 must be reported as a hazardous air pollutant, the Electric Power Research Institute (EPRI) has developed a widely-accepted method for estimating those emissions. We have created an Excel workbook derived from that EPRI method and used it to predict that additional H_2SO_4 emissions from several PacifiCorp units. Our analyses (Appendix B) indicate a two-orders-of-magnitude overestimation by EPA R8 of these visibility-impairing emissions, which results in an underestimation of the visibility benefit of adding SCR.

Visibility Metrics
In its BART analyses, PacifiCorp stated that costs per deciview of $5.6 million - $18.5 million per deciview are "reasonable," and that it is even reasonable to spend $31.7 million per dv to reduce NOx emissions at its Dave Johnston power plant. Furthermore, these PacifiCorp conclusions are consistent with those reached across the country[24] that the average cost per dV proposed by either a state or a BART source is $14 - $18 million, with a maximum of almost $50 million per dv proposed by Colorado at the Martin Drake power plant.

Cumulative Impacts
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. If reducing emissions from a BART source impacts multiple Class I areas, then a BART determination should incorporate those benefits. It is not justified to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired by the BART source. If emissions from the BART source are reduced, the benefits will be spread well beyond only the most-impacted Class I area, and these benefits are an integral part of the BART determination.[25]

The BART Guidelines attempt to create a workable approach to estimating visibility impairment. The Guidelines do not attempt to address the geographic extent of the impairment, but in effect assume that all Class I areas are created equal, i.e., widespread impacts in a large Class I area and isolated impacts in a small Class I area are given equal weight for BART determination purposes. To address the problem of geographic extent, we look at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there may be more sophisticated approaches to this problem, we believe that this is the

[23] Proposed Rule: Approval and Promulgation of Air Quality Implementation Plans; State of Nevada; Regional Haze State and Federal Implementation Plans Technical Support Document (TSD) Docket Number: EPA-R09-OAR-2011-0130 Prepared and Reviewed by: Scott Bohning, Eugene Chen, Steve Frey, Ann Lyons, Colleen McKaughan, Thomas Webb April 2, 2012

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

[25] 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, SJGS, and the Four Corners Power Plant. EPA also sums impacts and benefits in proposing that the Clean Air Transport Rule is "better-than-BART."

most practical, given current modeling techniques and information available. EPA R6 took a similar position regarding its BART determination for the San Juan Generating Station (SJGS):

> We agree with the NPS and the USDA Forest Service on the utility of a cumulative visibility metric in addition to the other visibility metrics we utilized and we do not agree that our approach is inconsistent with BART guidelines. Our visibility modeling shows that a number of Class I areas are individually and significantly impacted by emissions from the SJGS. The number of days per year significantly impacted by the facility's NO_X emissions is expected to decrease drastically at each Class I area (Table 6-8 of the TSD) as the result of installation of NO_X BART emission controls at the SJGS. Clearly, the visibility benefits from NO_X BART emission reductions will be spread among all affected Class I areas, not only the most affected area, and should be considered in evaluation of benefits from proposed reductions.
>
> In fully considering the visibility benefits anticipated from the use of an available control technology as one of the factors in selection of NO_X BART, it is appropriate to account for visibility benefits across all affected Class I areas and the BART guidelines provide the flexibility to do so. One approach as noted above is to qualitatively consider, for example, the frequency, magnitude, and duration of impairment at each and all affected Class I areas. Where a source such as the SJGS significantly impacts so many Class I areas on so many days, the cumulative `total dv' metric is one way to take magnitude of the impacts of the source into account.
>
> We concluded that a quantitative analysis of visibility impacts and benefits at only the Mesa Verde area would not be sufficient to fully assess the impacts of controlling NOX emissions from the SJGS.
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> Again, nothing in the RHR suggests that a state (or EPA in issuing a FIP) should ignore the full extent of the visibility impacts and improvements from BART controls at multiple Class I areas. Given that the national goal of the program is to improve visibility at all Class I areas, it would be short-sighted to limit the evaluation of the visibility benefits of a control to only the most impacted Class I area. As noted previously, NMED and PNM's BART analyses also presented visibility impact and improvement projections at all 16 Class I areas. We believe such information is useful in quantifying the overall benefit of BART controls. [26]

In its October 26, 2010 letter to the Colorado Department of Public Health and Environment, EPA R8 states:

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[26] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 52, EPA-R06-OAR-2010-0846; FRL-9451-1, Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination, AGENCY: Environmental Protection Agency (EPA). ACTION: Final rule. Federal Register / Vol. 76, No. 162 / Monday, August 22, 2011

> The visibility results section in each analysis only addresses visibility improvements at the most-impacted Class I area. Since visibility improvements are also likely at other nearby Class I Areas, the State needs to provide visibility modeling information for other Class I areas. This information will help inform the selection of BART.

It would be appropriate for EPA R8 to use the same approach for Wyoming as it recommended to Colorado.

Additionally, EPA R1 considered cumulative benefits in evaluating New Hampshire's regional haze plan.[27] And, EPA R2 also required a cumulative visibility analysis for the New York State Regional Haze SIP. EPA R2's analysis states:

> In making BART determinations, EPA also recommends the consideration of cumulative impacts and improvements that could occur at all of the Class I areas a particular facility might impact. EPA's analysis of the cumulative visibility improvements at all 7 Class I areas justifies a more stringent BART emission limit.

EPA Region 9's current proposal regarding Arizona's RH SIP includes this description of how it evaluated the degree of visibility improvement:[28]

> Table 17 shows the impact for the base case and the improvement from that baseline impact when controls are applied, all in deciviews, for each area. The Class I area types are National Monument (NM), Wilderness Area (WA), and National Park (NP). Also shown are the cumulative deciviews, the simple sum of impacts or improvements over all the Class I areas, and the number of areas with a baseline impact or improvement of at least 0.5 dv. Finally, the table includes two "dollars per deciview" measures of cost-effectiveness, both of which take the annual cost of the control in millions of dollars per year, and divides by an improvement in deciviews. For the first metric, "$/max dv", cost is divided by the deciview improvement at the Class I area with the greatest improvement. The second metric, "$/cumulative dv", divides cost by the cumulative deciview improvement. In assessing the degree of visibility improvement from controls, EPA relied heavily on the maximum dv improvement and the number of areas showing improvement, with cumulative improvement providing a supplemental measure that combines information on the number of areas and on individual area improvement. The dollars per deciview metrics provided information supplemental to the dollars per ton that was considered in the cost factor.

WY DEQ evaluated cumulative visibility improvements at the nearest Class I areas, while EPA R8 reported results for only one Class I area near each EGU.

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[27] ENVIRONMENTAL PROTECTION AGENCY40 CFR Part 52, [EPA–R01–OAR–2008–0599; A–1–FRL–9639–1], Approval and Promulgation of Air Quality Implementation Plans; New Hampshire; Regional Haze AGENCY: Environmental Protection Agency, ACTION: Proposed rule., Federal Register /Vol. 77, No. 39 /Tuesday, February 28, 2012

[28] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 51 [EPA-R09-OAR-2012-0021] Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans AGENCY: Environmental Protection Agency (EPA) ACTION: Proposed rule.

WY DEQ and EPA R8 have placed undue weight on incremental costs and incremental benefits. WY DEQ and EPA R8 have essentially based their BART and Reasonable Progress determinations on incremental costs and incremental benefits. (In almost every case, WY DEQ stated that the average cost-effectiveness of the proposed BART technologies for NO_X are all reasonable.) However, in discussing average and incremental costs, EPA BART Guidelines explain:

> The average cost (total annual cost/total annual emission reductions) for each may be deemed to be reasonable. However, the incremental cost of the additional emission reductions to be achieved may be very great. In such an instance, it may be inappropriate to choose control B, based on its high incremental costs, even though its average cost may be considered reasonable.

Although EPA does not explain in its BART Guidelines what it considers "very great" and "high" incremental costs, it goes on to provide an example of how incremental cost is calculated, and explains:

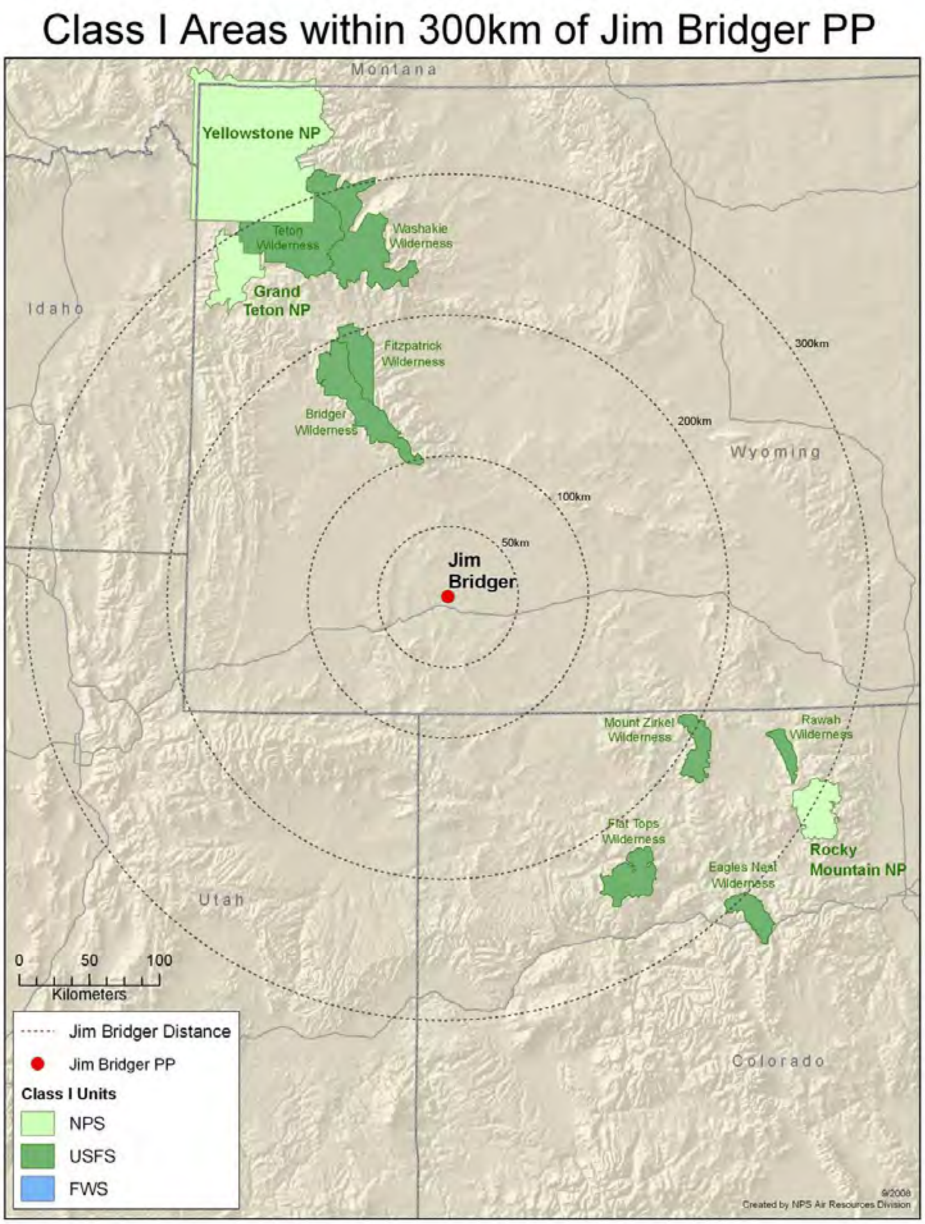
> The incremental cost of Option 1, then, is $20,000 per ton, 11 times the average cost of $1,900 per ton.

The clear implication of EPA's advice in the BART Guidelines is that incremental costs become a deciding factor only if they greatly exceed average costs. Instead, EPA R8 has determined that incremental costs only twice the "reasonable" average costs are excessive. In doing so, EPA R8 ignores the established fact that pollution control costs increase exponentially with control efficiency, which means that incremental costs will always exceed average costs.

Incremental visibility improvement is not mentioned in the Reasonable Progress provisions or BART Guidelines and EPA R8 cannot create a new criterion for the sole purpose of eliminating a control option that is reasonably cost-effective and would yield a significant visibility improvement. If EPA is going to compare costs and visibility benefits, it must do so in a transparent and objective manner, and state its criteria for acceptance or rejection of a control strategy. Relatively subjective statements about costs being "high" or visibility improvements "small" are not sufficient to justify the decisions.

National Park Service (NPS) Comments on EPA Region 8's proposed Best Available Retrofit Technology (BART) Determination for Jim Bridger Power Plant
August 3, 2012

Facility Background PacifiCorp' Jim Bridger Power Plant (Bridger) is comprised of four identically-sized tangentially-fired boilers burning sub-bituminous coal with a total generating capacity of 2,251 megawatts (MW).[1] According to EPA's Clean Air Markets (CAM) database, 2011 NO_x emissions from Bridger were 13,175 tons which ranked the plant #27 in the U.S. There are eleven Class I areas within 300 km of Bridger:



[1] Based on EPA's Clean Air Markets data for 2001 – 2003.

Bridger Unit 1 was placed in service in 1974. Unit 2 commenced service in 1975. Unit 3 entered service in 1976 followed by Unit 4, which commenced service in 1979. All units are BART-eligible. Each unit was initially equipped with early generation Low-NO_X Burners (LNB) manufactured by Combustion Engineering to control emissions of NO_X. They are also equipped with dry Flakt wire-frame electrostatic precipitators (ESPs) to control PM. Finally, to control SO_2 emissions, each unit is equipped with a three-absorber-tower wet sodium flue gas desulfurization (WFGD) system made by Babcock & Wilcox.

On April 1, 2005, Permit MD-1138 was issued by WY DEQ to PacifiCorp to replace the first generation LNB on Unit 2 with a new ALSTOM TFS 2000TM low-NO_X firing system including two elevations of separated overfire air (SOFA). The new LNB were installed and placed into service May 29, 2005. The permitted NO_X emission limit of 0.26 lb/mmBtu, annual average, authorized in MD-1138 for Unit 2 went into effect in 2005.

On October 6, 2006, after the LNB modification to Unit 2 was completed, PacifiCorp submitted a construction permit application to modify Units 1, 2, 3 and 4 by replacing the existing first generation LNBs on Units 1, 3 and 4 with Alstom TFS 2000TM LNB with two elevations of SOFA, install a flue gas conditioning (FGC) system which injects SO_3 gas into the flue gas to improve the efficiency of the ESPs on Units 1-4, and upgrade the existing FGD systems on all four units to achieve greater than 90% SO_2 removal.

Permit MD-1552 was issued by WY DEQ on April 9, 2007 authorizing the new LNB, FGC, and WFGD modifications to Bridger. The LNB upgrades to Unit 3 started up May 30, 2007. The new LNBs on Unit 4 started up June 8, 2008. The final LNB upgrade occurred in 2010 on Unit 1.

Modifications to the scrubber vessels on Unit 4 were not necessary in order to meet the SO_2 emission limits permitted in MD-1552. Unit 4 can meet the limits by reducing the amount of flue gas bypassing the scrubber. However, this would increase the moisture content of the gas entering the exhaust stack and modifications to the stack drain system were required to accommodate the increased moisture. Upon completion of wet scrubber upgrades permitted in MD-1552, the SO_2 limits for the corresponding unit become 0.15 lb/mmBtu on a 12-month rolling average and 900 lb/hr on a 24-hr rolling average.

BART Analysis for NO_x

The presumptive NO_X BART limit for a plant with capacity greater than 750 MW and burning sub-bituminous coal in a tangentially-fired boiler is 0.15 lb/mmBtu. PacifiCorp contends that actual data demonstrate that, for the Bridger units burning a combination of the Bridger, Black Butte, and Leucite Hill coals, the likely NO_X emission rate will be closer to the bituminous (0.28 lb/mmBtu) BART presumptive NO_X limit. However, documents submitted by PacifiCorp state:

> As shown in Table 1, although Bridger, Black Butte, Leucite Hills, and Naughton are classified as subbituminous, they all exhibit higher nitrogen content, lower moisture content, and lower oxygen content than the PRB coal.[2]
>
> The coals fired at Jim Bridger Station are generally classified (ranked) by ASTM Standards as Western Sub-Bituminous "B" and "C" coals...[3]

We believe that the burden is on PacifiCorp to show that the lower (0.15 lb/mmBtu) presumptive BART limit does not apply to this plant.

WY DEQ has underestimated the ability of SCR to reduce emissions.

In estimating the annual cost-effectiveness of the LNB/SOFA+SCR option, WY DEQ assumed 0.07 lb/mmBtu on an annual average basis. Based on the 0.026 lb/mmBtu NO_X emission rate predicted for the LNB/SOFA option, and the 0.20 lb/mmBtu annual emission rates demonstrated by all four Bridger units, outlet emissions at 0.07 lb/mmBtu represent only a 65% - 73% SCR control efficiency as opposed to the generally-accepted 90%. WY DEQ has not provided any documentation or justification to support the higher emission rates used in its analyses. In other recent BART actions, EPA has determined that SCR can achieve 0.05 lb/mmBtu on an annual basis. Such an underestimate at Bridger biases the cost-benefit analysis against SCR and is inconsistent with other EPA analyses.

WY DEQ has overestimated the cost of SCR.

Figure 3 of a survey of industry SCR cost data (conducted for the Utility Air Regulatory Group and included in Appendix A) and EPA Integrated Planning Model (IPM) estimates show that typical SCR costs for units the size of the Bridger units would be $170 - $270/kW.[4] WY DEQ's cost estimates for SCR are $314/kW, which exceed real-world industry costs ($50 - $300/kW) and industry estimates, leading us to believe that capital and annual costs are overestimated. Neither PacifiCorp nor WY DEQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and PacifiCorp and WY DEQ did not use the Control Cost Manual (CCM). (For example, the cost estimates[5] used by WY DEQ contained Owner's Costs and Allowance for Funds Utilized During Construction, which are not allowed by

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[2] T E C H N I C A L M E M O R A N D U M, Coal Quality and Nitrogen Oxide Formation, PREPARED FOR: Bill Lawson/PacifiCorp, PREPARED BY: CH2M HILL, COPIES: Mike Jenkins/PacifiCorp, DATE: January 28, 2009

[3] NOx VARIATION WITH WESTERN U.S. SOURCED COALS FIRED IN PACIFICORP UTILITY BOILERS ALSTOM, Inc., Windsor, CT, February 4, 2005

[4] "OVERVIEW OF INFORMATION ON PROJECTED CONTROL TECHNOLOGY COSTS AND PERFORMANCE AS DEVELOPED FOR EPA'S INTEGRATED PLANNING MODEL (IPM)" October 15, 2010, Prepared by J. Edward Cichanowicz for the Utility Air Regulatory Group

[5] BART Analysis for Jim Bridger Unit 1 (2, 3 & 4) Prepared For: PacifiCorp, December 2007, Prepared By: CH2MHill

the CCM and have been rejected by EPA R8 in other analyses. The total for these improper costs exceeds $12 million per SCR.)

In conducting our cost analysis of SCR at Bridger, we used an approach similar to that used by EPA R8 in its evaluation of SCR on the Colstrip power plant. For Bridger Unit 1, we used EPA's IPM model to estimate Direct Capital Cost (DCC) at $85 million.[6] We used the IPM estimate for DCC and then applied the EPA CCM factors (totaling 141%) for Indirect Capital Cost to estimate a Total Capital Investment (TCI) of $119 million ($212/kW) which is consistent with industry data, but lower than the WY DEQ estimate. Next, we applied the CCM methods for estimating Direct and Indirect Annual Costs to the TCI and arrived at a Total Annual Cost of $16 million for LNB+SOFA+SCR versus $20 million by WY DEQ. We concluded that LNB+SOFA+SCR for Unit 1 would remove over 7,358 tpy and cost about $2,233/ton (compared to 8,987 tpy removed at $2,258/ton estimated by WY DEQ). The Incremental Cost of adding SCR would be $3,400/ton. We estimated the cost-effectiveness for addition of SCR to Bridger Units 2, 3, and 4 in the same manner, and our results are shown in Table 1 and details can be found in Appendix JB.

[6] after adjusting to 2010$ using the CEPCI

Table 1. NPS estimates of LNB+OFA+SCR costs for Bridger

Unit	BW71	BW72	BW73	BW74
Uncontrolled Emissions (tpy)	8,432	7,575	7,836	8,127
Uncontrolled Emissions (lb/mmBtu)	0.39	0.37	0.37	0.40
Combustion Controls Cost-benefit Analysis				
Control Efficiency	34%	30%	30%	34%
Controlled emissions (lb/mmBtu)	0.26	0.26	0.26	0.26
Controlled Emissions (tpy)	5,587	5,317	5,482	5,334
Emissions Reduction (tpy)	2,845	2,258	2,355	2,793
Capital Cost	$ 11,300,000	$ 11,300,000	$ 11,300,000	$ 11,300,000
Capital Cost ($/kW)	$ 20	$ 20	$ 20	$ 20
O&M Cost				
Annualized Cost	$ 1,144,944	$ 1,144,944	$ 1,144,944	$ 1,144,944
Cost-Effectiveness ($/ton)	$ 402	$ 507	$ 486	$ 410
SCR Cost-benefit Analysis				
Control Efficiency	81%	81%	81%	81%
Controlled emissions (lb/mmBtu)	0.05	0.05	0.05	0.05
Emissions Reduction (tpy)	4,513	4,294	4,428	4,309
Capital Cost	$ 119,460,589	$ 122,226,029	$ 117,531,196	$ 122,895,451
Capital Cost ($/kW)	$ 212	$ 217	$ 209	$ 218
O&M Cost	$ 4,007,164	$ 3,966,017	$ 3,936,483	$ 3,984,125
Annualized Cost	$ 15,283,399	$ 15,503,290	$ 15,030,597	$ 15,584,586
Cost-Effectiveness ($/ton)	$ 3,387	$ 3,610	$ 3,395	$ 3,617
Combustion Controls + SCR Cost-benefit Analysis				
Control Efficiency	87.3%	86.5%	86.5%	87.4%
Controlled Emissions (tpy)	1,074	1,022	1,054	1,026
Emissions Reduction (tpy)	7,358	6,552	6,782	7,101
Capital Cost	$ 130,760,589	$ 133,526,029	$ 128,831,196	$ 134,195,451
Capital Cost ($/kW)	$ 232	$ 237	$ 229	$ 238
O&M Cost	$ 4,007,164	$ 3,966,017	$ 3,936,483	$ 3,984,125
Annualized Cost	$ 16,428,343	$ 16,648,234	$ 16,175,541	$ 16,729,530
Cost-Effectiveness ($/ton)	$ 2,233	$ 2,541	$ 2,385	$ 2,356

Even though WY DEQ underestimated the effectiveness and overestimated the cost of SCR, it determined that "The cost effectiveness values are reasonable…" Our analysis agrees.

EPA R8 has incorrectly estimated visibility improvement from all NO_X control options. (Please see our general comments.)

EPA R8 has underestimated visibility improvement from SCR.

(Please see our general comments.) WY DEQ evaluated visibility improvements at the three nearest Class I areas—Bridger, Fitzpatrick, and Mount Zirkel Wilderness Areas (WA)—and reported the "cumulative 3-year averaged visibility improvement from Post-Control Scenario A across the three Class I areas..." We requested to WY DEQ that the other eight Class I areas within 300 km of Bridger (Grand Teton National Park (NP), Yellowstone NP, Rocky Mountain NP, Washakie WA, Teton WA, Flat Tops WA, Rawah

WA, and Eagles Nest WA) be included in the modeling analysis. However, instead of expanding the modeling analysis, EPA R8 reported results for only the Mount Zirkel Wilderness Area (WA). [7]

BART Analysis for PM_{10}

The fabric filter option discussed by WY DEQ represents PacifiCorp's estimate that application of a Compact Hybrid Particulate Collector (COHPAC) unit in addition to using FGC with the existing ESPs can reduce emissions an additional 50% resulting in a PM_{10} emission rate of 0.015 lb/mmBtu. Considering that EPA R9 proposed that the Desert Rock power plant meet 0.010 lb/mmBtu, we believe that the COHPAC option could achieve the same limit.

Neither WY DEQ nor EPA R8 completed the five-step BART process for PM_{10} emissions. EPA asserted that:

> The State did not provide visibility improvement modeling for fabric filters, but EPA is proposing to conclude this is reasonable based on the high cost effectiveness of fabric filters at each of the units. In addition, we anticipate that the visibility improvement that would result from lowering the limit from 0.03 lb/MMBtu to 0.015 lb/MMBtu would be insignificant based on the State's analysis.

We have several concerns with these conclusions:

- EPA R8 cannot simply abort the five-step process once it has determined a technology to be technically feasible.
- EPA R8 has overlooked the environmental impact of SO_3 emissions that may be released as a result of PacifiCorp's Flue Gas Conditioning BART proposal.[8]
- WY DEQ has underestimated the effectiveness of the fabric filter option.
- WY DEQ's fabric filter costs are overestimated. For example, the cost estimates[9] used by WY DEQ contained Escalation, extra Contingencies, and Allowance for Funds Utilized During Construction, which are not allowed by the Control Cost manual and have been rejected by EPA R8 in other analyses. The total for these improper costs exceeds $7 million per fabric filter.

Even taken at face value, the cost/ton deemed "high" by EPA R8 for Units 2 and 3 are similar to or lower than cost/ton values accepted as reasonable (for NO_X) by states and by EPA in other analyses.

EPA R8 should complete a proper five-step PM_{10} BART analysis by re-evaluating the COHPAC option on the basis of its ability to achieve a lower limit (e.g., 0.010

[7] It is our understanding that EPA modeled impacts at several additional Class I areas.
[8] "Does SO3 Flue Gas Conditioning Have an Impact on the Environment—An Assessment" M.J. Beeslaar, Eskom Enterprises
[9] BART Analysis for Jim Bridger Unit 1 (2, 3 & 4) Prepared For: PacifiCorp, December 2007, Prepared By: CH2MHill

lb/mmBtu), evaluating costs in accordance with the BART Guidelines, comparing its cost-effectiveness to other baghouse installations to properly assess the “reasonableness” of its cost, and determining the degree of visibility improvement that would result from a lower PM_{10} limit.

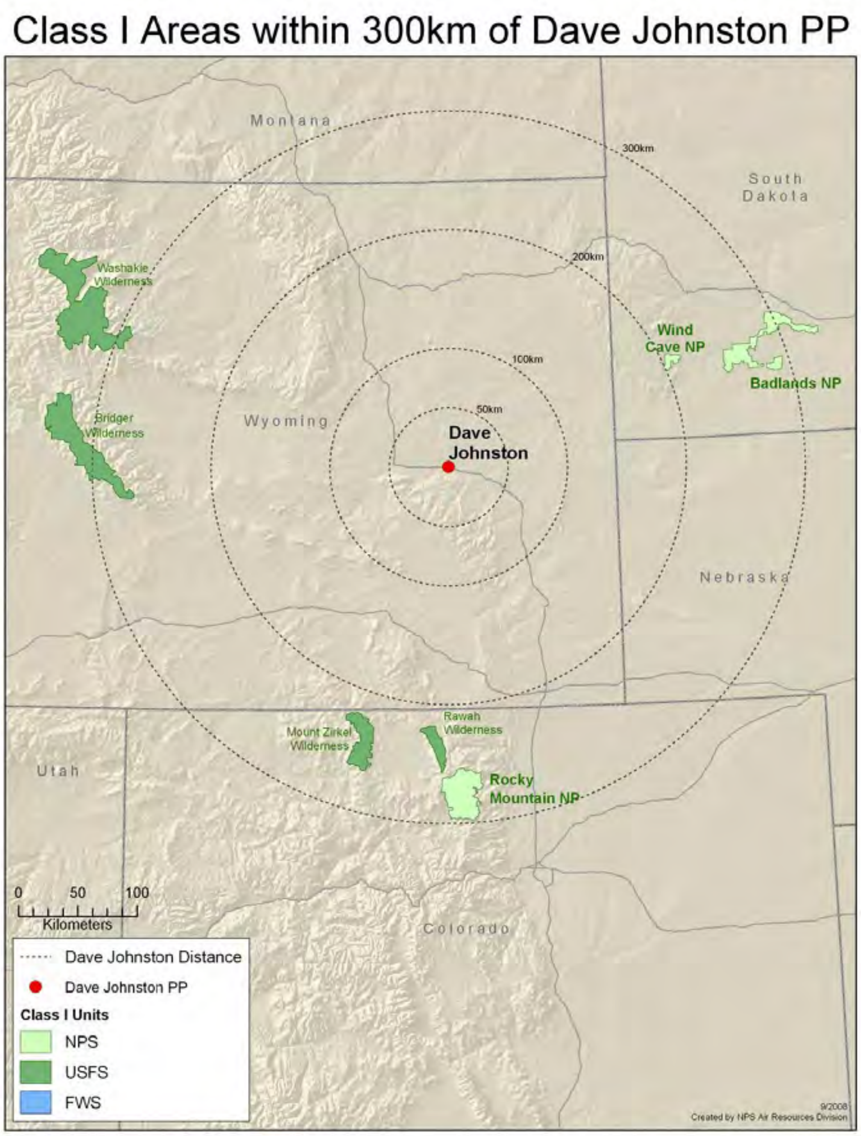
Conclusions:

- WY DEQ has underestimated the ability of SCR to reduce emissions. EPA Regions 6, 8 & 9 have recently determined that SCR can achieve 0.05 lb/mmBtu on an annual basis in NM, MT and AZ. EPA R8 should apply the same limits for Wyoming.
- WY DEQ has overestimated the cost of SCR by allowing methods to be used and costs to be included in the Wyoming BART analyses that EPA has disallowed in other states.
- EPA R8 has underestimated visibility improvement from SCR by not evaluating its cumulative benefits across the multiple Class I areas impacted.
- We agree with EPA R8 that SCR represents BART for all four Bridger units, but recommend a lower 30-day rolling average emission limit (e.g. 0.06 lb/mmBtu) to reflect the true capabilities of SCR.
- EPA R8 has not completed a proper five-step PM_{10} BART analysis.

National Park Service (NPS) Comments on EPA Region 8's proposed Best Available Retrofit Technology (BART) and Reasonable Progress Determinations for the Dave Johnston Power Plant August 3, 2012

Facility Background

PacifiCorp's Dave Johnston Power Plant (Johnston) is comprised of four units burning pulverized sub-bituminous Powder River Basin coal for a total gross generating capacity of (at least) 852 megawatts (MW) based upon 2001 - 2003 data from EPA's Clean Air Markets (CAM) database. According the CAM database, 2011 NO_x emissions from Johnston were 7,181 tons which ranked the plant #82 in the U.S. There are seven Class I areas within 300 km of Johnston:



Johnston Units 1 and 2 are dry bottom wall-fired units that generated up to 119 and 116 MW, respectively, during 2001 – 2003. Unit 1 began operation in 1958 and Unit 2 in 1960. Since both units were in operation before August 7, 1962 they are not subject to BART regulation. SO_2 emissions are uncontrolled and 2011 emissions averaged 0.8 lb/mmBtu. NO_X emissions are uncontrolled and 2011 emissions averaged 0.4 lb/mmBtu. PM emissions are controlled using an electrostatic precipitator. According the CAM database, 2011 NO_x emissions from Johnston Units 1 and 2 were 1,513 and 1,824 tons, respectively, which ranked these units #409 and #342 in the U.S.

Johnston Unit 3 commenced service in 1964 and is subject to BART review. It was manufactured by Babcock & Wilcox and equipped with burners in a cell configuration. (It is the only boiler in Wyoming subject to BART with burners in a cell configuration.) During 2001 – 2003, Johnston Unit 3 generated up to 251 MW. The original burners were upgraded to Low-NOx Burner (LNB) Technology w/Overfire Air (OFA) which began May 23, 2010. The presumptive NO_X limit is 0.45 lb/mmBtu and 2011 emissions averaged 0.23 lb/mmBtu. According to the CAM database, 2011 NO_x emissions were 1,990 tons, which ranked #315 in the U.S. Johnston Unit 3 was not equipped with any SO_2 control equipment until a dry Lime FGD began on May 29, 2010 and 2011 emissions averaged 0.074 lb/mmBtu. PM emissions from Unit 3 were controlled using a Lodge-Cottrell single-chamber ESP installed in 1976 until a fabric filter was installed in 2011.

Johnston Unit 4 is a tangentially-fired boiler manufactured by Combustion Engineering, (now Alstom) and commenced service in 1972 and is subject to BART review. During 2001 – 2003, Johnston Unit 4 generated up to 366 MW. The original burners were replaced in 1976 with concentric-firing first generation LNB and were upgraded to LNB Technology w/Separated OFA which began Jun 12, 2009. The presumptive NO_X limit is 0.15 lb/mmBtu and 2011 emissions averaged 0.14 lb/mmBtu. According the CAM database, 2011 NO_x emissions were 1,853 tons, which ranked #337 in the U.S. A Venturi scrubber is used to control PM emissions. Additional SO_2 emission control is achieved in the scrubber by adding lime to the scrubber liquor and 2011 emissions averaged 0.32 lb/mmBtu.

On June 27, 2008, air quality Permit MD-5098 was issued by WY DEQ to PacifiCorp to install dry flue gas desulfurization control equipment on both Units 3 and 4 and replace the existing ESP on Unit 3 with a baghouse and install a new baghouse on Unit 4.

Units 3 & 4: BART Analysis for NO_x

WY DEQ has underestimated the ability of SCR to reduce emissions.

In estimating the annual cost-effectiveness of the LNB+OFA+SCR option, WY DEQ assumed 0.07 lb/mmBtu on an annual average basis. Based on the 0.28 lb/mmBtu NO_X emission rate predicted for the LNB+OFA option, and the 0.23 lb/mmBtu annual emission rates demonstrated by Johnston Unit 3 in 2011, outlet emissions at 0.07 lb/mmBtu represent only a 70% - 75% SCR control efficiency as opposed to the generally-accepted 90%. Based on the 0.15 lb/mmBtu NO_X emission rate predicted for the LNB+OFA option, outlet emissions at 0.07 lb/mmBtu represent only a 53% SCR control efficiency on Unit 4. WY DEQ has not provided any documentation or justification to support the higher emission rates used in its analyses. In other recent BART actions, EPA has determined that SCR can achieve 0.05 lb/mmBtu on an annual basis. Such an underestimate at Johnston biases the cost-benefit analysis against SCR and is inconsistent with other EPA analyses.

WY DEQ has overestimated the cost of SCR.

Figure 3 of a survey of industry SCR cost data (conducted for the Utility Air Regulatory Group and included in Appendix A) and EPA Integrated Planning Model (IPM) estimates show that typical SCR costs for units the size of the Johnston units would be $180 - $300/kW.[1] WY DEQ's cost estimates for SCR on Units #3 and #4 are $488 and $436/kW, respectively, which exceed real-world industry costs ($50 - $300/kW) and industry estimates, leading us to believe that capital and annual costs are overestimated. Neither PacifiCorp nor WY DEQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and PacifiCorp and WY DEQ did not use the Control Cost Manual (CCM). For example, the cost estimates[2] used by WY DEQ contained Allowance for Funds Utilized During Construction, which is not allowed by the CCM and has been rejected by EPA R8 in other analyses. The total for these improper costs exceeds $13 million. As a result, we believe that capital and annual costs are overestimated.

In conducting our cost analysis of SCR at Johnston, we used an approach similar to that used by EPA R8 in its evaluation of SCR on the Colstrip power plant. For Johnston Unit 3, we used EPA's IPM model to estimate Direct Capital Cost (DCC) at $43 million.[3] We then applied the EPA CCM factors (totaling 141%) for Indirect Capital Cost to estimate a Total Capital Investment (TCI) of $61 million ($242/kW) which is consistent with industry data, but less than half of the WY DEQ estimate. Next, we applied the CCM methods for estimating Direct and Indirect Annual Costs to the TCI and arrived at a Total Annual Cost of $9.3 million for LNB+OFA+SCR versus $16.3 million by WY DEQ. We concluded that LNB+OFA+SCR for Unit 3 would remove 4,493 tpy and cost $2,079/ton (compared to 5,041 tpy removed at $3,243/ton estimated by WY DEQ). We estimated $2,726/ton cost-effectiveness for addition of SCR to Johnston Unit 4 in the same manner, our results are shown in Table 1, and details can be found in Appendix DJ.

[1] "OVERVIEW OF INFORMATION ON PROJECTED CONTROL TECHNOLOGY COSTS AND PERFORMANCE AS DEVELOPED FOR EPA'S INTEGRATED PLANNING MODEL (IPM)" October 15, 2010, Prepared by J. Edward Cichanowicz for the Utility Air Regulatory Group

[2] "Best Available Retrofit Technology Modeling Refinements" July 24, 2008

[3] after adjusting to 2010$ using the CEPCI

Table 1. NPS cost estimates for SCR at Dave Johnson Units 3 and 4.

Unit	Unit #3	Unit #4	Data Source
Uncontrolled Emissions (tpy)	4,973	5,137	OAQPS Control Cost Manual
Uncontrolled Emissions (lb/mmBtu)	0.52	0.37	CAMD 2001 - 2003
Combustion Controls Cost-benefit Analysis			
Control Efficiency	56%	61%	calculated
Controlled emissions (lb/mmBtu)	0.23	0.14	CAMD 2011
Controlled Emissions (tpy)	2,172	2,005	calculated
Emissions Reduction (tpy)	2,801	3,132	calculated
Capital Cost	$ 17,500,000	$ 17,500,000	WY DEQ report (2006 $)
Capital Cost ($/kW)	$ 70	$ 48	calculated
O&M Cost	$ 100,000	$ 100,000	CAMD 2011
Annualized Cost	$ 1,764,775	$ 1,764,775	EPA report
Cost-Effectiveness ($/ton)	$ 630	$ 564	calculated
SCR Cost-benefit Analysis			
Control Efficiency	78%	72%	OAQPS Control Cost Manual
Controlled emissions (lb/mmBtu)	0.05	0.04	NPS assumption
Emissions Reduction (tpy)	1,691	1,452	OAQPS Control Cost Manual
Capital Cost	$ 60,774,547	$ 88,036,208	calculated
Capital Cost ($/kW)	$ 242	$ 241	calculated
O&M Cost	$ 1,839,561	$ 2,421,185	OAQPS Control Cost Manual
Annualized Cost	$ 7,576,248	$ 10,731,181	OAQPS Control Cost Manual
Cost-Effectiveness ($/ton)	$ 4,479	$ 7,393	OAQPS Control Cost Manual
Combustion Controls + SCR Cost-benefit Analysis			
Control Efficiency	90.3%	89.2%	calculated
Controlled Emissions (tpy)	480	554	calculated
Emissions Reduction (tpy)	4,493	4,583	calculated
Capital Cost	$ 78,274,547	$ 105,536,208	calculated
Capital Cost ($/kW)	$ 311	$ 288	calculated
O&M Cost	$ 1,939,561	$ 2,521,185	calculated
Annualized Cost	$ 9,341,023	$ 12,495,956	calculated
Cost-Effectiveness ($/ton)	$ 2,079	$ 2,726	calculated

Despite the overestimated SCR costs, the $2,200 - $3,300 cost/ton estimates by WY DEQ and accepted by EPA R8 for SCR are similar to or lower than the cost/ton values accepted as reasonable in other BART analyses. WY DEQ stated that "The cost effectiveness of the four proposed BART technologies for NOx are all reasonable."

EPA R8 appears to have placed undue weight on incremental costs.

EPA R8 states:

- (Unit 3) Incremental cost effectiveness for the controls evaluated is as follows: LNB with advanced OFA and SCR: $10,234/ton.
- (Unit 4) The incremental cost effectiveness of achieving 0.07 lb/ MMBTU with SCR over achieving 0.15 lb/MMBTU with LNBs is $17,662…

Our analysis (above) of the LNB+OFA+SCR option shows incremental costs of $4,479/ton for adding SCR to LNB+OFA on Johnston Unit 3 and $7,393/ton for adding

SCR to LNB+OFA on Johnston Unit 4. For comparison, in its proposal to disapprove part of the North Dakota plan, EPA R8 cited the "…relatively low incremental cost effectiveness between the two control options ($4,855 per ton)…"

For Johnston units 3 and 4, the NPS estimates of incremental costs of SCR are two – three times greater than LNB+OFA+SCR's average costs, which are reasonable when compared to costs accepted by other states and EPA.

EPA R8 has incorrectly estimated visibility improvement from all NO_X control options.

(Please see our general comments.) WY DEQ evaluated visibility improvements at the four nearest Class I areas and reported the "The cumulative 3-year averaged 98th percentile visibility improvement from Post-Control Scenario A summed across all four Class I areas achieved with Post-Control Scenario B was 0.754 Δdv from Unit 3 and 0.405 Δdv from Unit 4." EPA R8 reported results for only one Class I area.

PacifiCorp apparently considered cost/dV a useful metric when it made the following statements for its Unit #3 BART proposal: "the incremental cost effectiveness for Scenario 1 compared to the Baseline is reasonable at $0.4 million per day and $14.4 million per dV to improve visibility at Badlands NP" and for its Unit #4 BART proposal, "the incremental cost effectiveness for Scenario 1 compared to the Baseline is reasonable at about $800,000 per day and $31.7 million per dV." PacifiCorp's conclusions are consistent with those reached across the country[4] that the average cost per dv proposed by either a state or a BART source is $14 - $18 million, with a maximum of almost $50 million per dv proposed by Colorado at the Martin Drake power plant.

Combining the modeling results provided by EPA R8 (which we believe have underestimated SCR benefits) and WY DEQ's cost analyses (which we believe have overestimated SCR costs), addition of SCR at Dave Johnston Unit 3 would improve visibility by 1.16 dv at a cost of $14 million per dv at the most-impacted Class I area. Likewise, addition of SCR at Dave Johnston Unit 4 would improve visibility by 0.97 dv at a cost of $17 million per dv. Not only is addition of SCR cost-effective (even by PacifiCorp's criteria), it would be even more cost-effective if the issues we have noted above are addressed.

By overestimating costs of SCR and underestimating control efficiency and visibility benefits, EPA R8 concluded that combustion controls plus SNCR is BART for Unit 3 and combustion controls are BART for Unit 4, rather than SCR.

Conclusions

- WY DEQ has underestimated the ability of Selective Catalytic Reduction (SCR) to reduce emissions.
- WY DEQ has overestimated the cost of SCR.

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

- EPA R8 has placed undue weight on incremental costs.
- EPA R8 has incorrectly estimated visibility improvement from all NO_X control options.
- EPA R8 did not consider cumulative benefits of improving visibility at multiple Class I areas.

For the reasons cited above, EPA R8's BART analysis for Johnston Unit 3 and Unit 4 is not acceptable. We believe that a proper BART analysis would conclude that addition of SCR is BART for Johnston Unit 3 and Unit 4.

Units 1 & 2: Reasonable Progress Analysis for NO_x

WY DEQ has underestimated the ability of combustion controls plus SCR to reduce emissions.

WY DEQ did not evaluate the effectiveness of the LNB+OFA+SCR option. Instead, WY DEQ assumed addition of SCR to these currently uncontrolled EGUs would only reduce NO_X emissions by 79% down to 0.12 lb/mmBtu on an annual average basis, although it is generally assumed that SCR can reduce NO_X emissions by 90% or down to 0.05 lb/mmBtu (or lower). WY DEQ has not provided any documentation or justification to support the higher emission rates used in its analyses. Such an approach at Johnston adversely biases the cost-benefit analysis and is inconsistent with other EPA analyses discussed above.

WY DEQ has used incorrect emission rates.

First, WY DEQ has assumed that Johnston Unit 1 and Unit 2 emitted at 0.57 lb/mmBtu on an annual basis and used this as the baseline condition from which to calculate the control efficiency it used for each control option. However, our review of CAM data back to 2000 shows that the highest annual NO_X emission rate for Unit 1 was 0.474 lb/mmBtu (2002) and 0.460 lb/mmBtu for Unit 2 (2006). For the 2001 – 2003 baseline period, annual NO_X emissions were 0.46 and 0.44 lb/mmBtu for Johnston Unit 1 and Unit 2, respectively. Thus, WY DEQ's proposal to reduce NO_X to 0.20 lb/mmBtu with LNB+OFA represents a 56% reduction instead of 65% assumed by WY DEQ.

As noted before, EPA R8 deviated from the BART Guidelines in the way it estimated the emission rates it used in is modeling analyses. For Johnston Unit 1 and Unit 2, EPA R8 assumed that NO_X emissions would drop from 1,012.5 lb/hr (base case) to 354.375 lb/hr with the addition of LNB+OFA and to 202.5 lb/hr with addition of SCR. However, our review of 2001 – 2003 daily CAM data found that daily NO_X emissions from Johnston Unit 1 and Unit 2 during 2001 – 2003 never exceeded 680 lb/hr. EPA R8's modeling analysis cannot be relied upon to estimate "a comparatively small incremental visibility improvement" because the emissions modeled are incorrect.

EPA R8 has misinterpreted the Reasonable Progress provisions of the Regional Haze Rule.

EPA R8's conclusion that addition of SCR is not justified due to the "small incremental visibility improvement" is based upon a flawed visibility analysis that over-values addition of LNB+OFA and under-values addition of SCR. Furthermore, the degree of visibility improvement is not one of the four statutory factors to be considered under the Reasonable Progress provisions of the Regional Haze Rule. Incremental visibility improvement is not mentioned anywhere in the Reasonable Progress provisions or BART Guidelines and EPA R8 cannot create a new criterion for the sole purpose of eliminating a control option that is reasonably cost-effective and would yield a significant visibility improvement.

Conclusions

Taken at face value, the EPA R8 analysis strongly supports the addition of SCR:

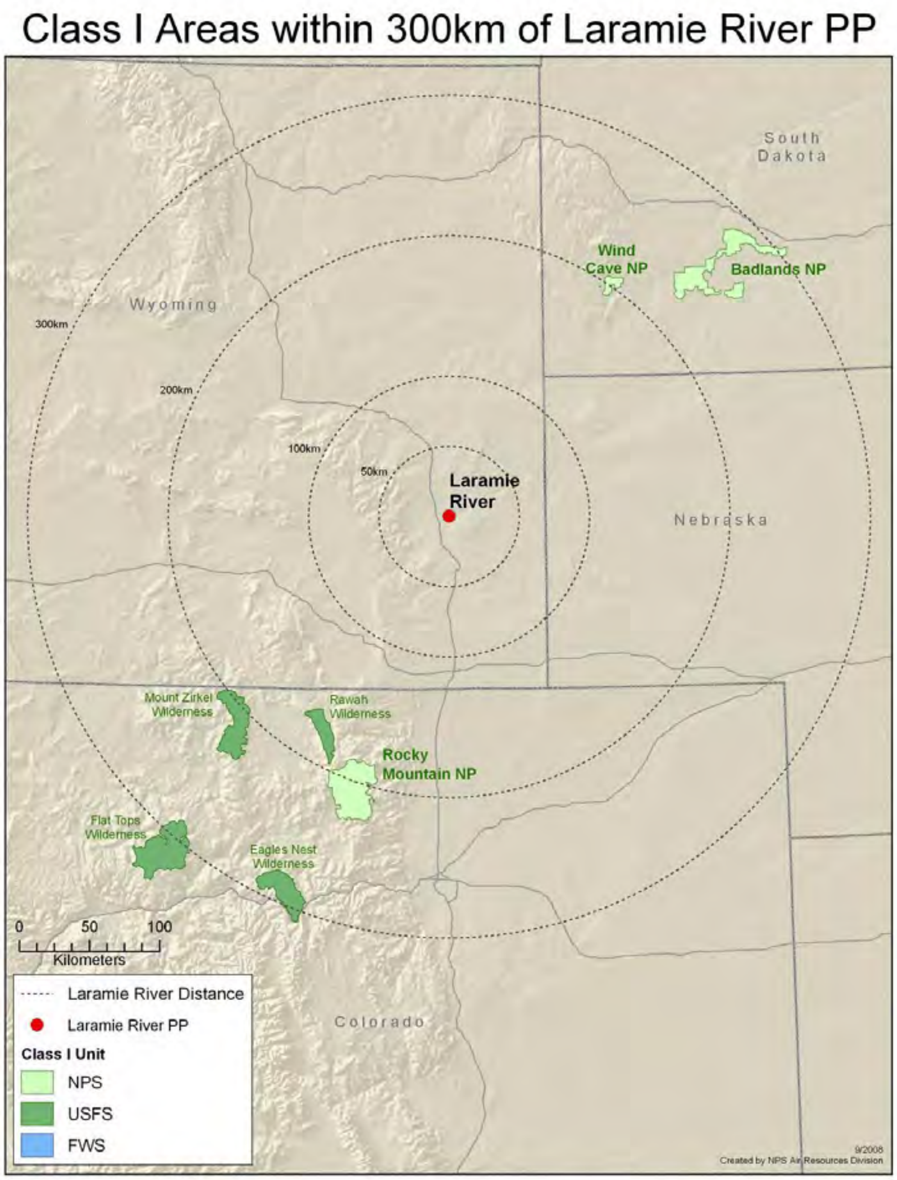
- Average cost-effectiveness is less than $1,900/ton.
- Visibility improvement is greater than 0.5 dv at one Class I area.

We recommend that EPA conclude that addition of SCR represents Reasonable Progress for Johnston Unit 1 and Unit 2.

National Park Service (NPS) Comments on EPA Region 8's proposed Best Available Retrofit Technology (BART) Determination for Laramie River Station Power Plant
August 3, 2012

Facility Background

Basin Electric's (Basin) Laramie River Station is comprised of three 590 MW (gross) dry-bottom, wall-fired boilers burning pulverized Powder River Basin sub-bituminous coal for a total gross generating capacity of 1,770 MW. Laramie River Unit 1 was placed in service in 1980. Unit 2 commenced service in 1981, and Unit 3 entered service in 1982. All units are BART-eligible. There are seven Class I areas within 300 km of the Laramie River Station:



Each unit is equipped with early generation Low-NOx burners (LNBs) to control emission of NO_X. Over-Fire Air (OFA) was added to Unit 1 in 2009, Unit 2 in 2010, and Unit 3 in 2011. Units are also equipped with cold-side electrostatic precipitators to control particulate matter emissions. Units 1 and 2 are equipped with wet flue gas desulfurization, and Unit 3 is equipped with a dry scrubber for SO_2 removal. The presumptive NO_X emission limit is 0.23 lb/mmBtu. According to EPA's Clean Air Markets (CAM) database, 2011 NO_x emissions from Laramie River were 14,058 tons which ranked the plant #22 in the U.S. (NO_X emissions are relatively similar across Units 1 - 3, which ranked #87, #77, and #71, respectively, in the US.)

BART Analysis for NO_x

WY DEQ has overestimated the ability of SNCR to reduce emissions.

EPA R8 is basing its BART determination on the assumption that LNB+OFA+SNCR can achieve 0.12 lb/mmBtu on a 30-day rolling average. (This means that addition of SNCR must reduce NO_X emissions from the LNB+OFA strategy by another 48%.[1] Given the sensitivity of SNCR to boiler operation, size, and configuration, we are concerned that SNCR may not be able to achieve the proposed level of performance on a consistent basis. For example, our query of CAM data for 2011 (included in Appendix C) found no EGUs with SNCR (out of 3,621 coal-fired EGUs) that met 0.12 lb/mmBtu each month.

WY DEQ has underestimated the ability of SCR to reduce emissions.

In estimating the annual cost-effectiveness of the LNB+OFA+SCR option, WY DEQ assumed 0.07 lb/mmBtu, which represents 74% control efficiency on an annual average basis, as opposed to the generally-accepted 90%. (Based on the 0.023 lb/mmBtu NO_X emission rate predicted for the LNB+OFA option, and the 0.18 – 0.22 lb/mmBtu annual

[1] For larger boilers (i.e., greater than 300 MW), there are numerous challenges associated with applying SNCR. In particular, such boilers' large physical dimensions pose challenges for injecting and mixing the reagent with the flue gas. Another issue with larger units is the fact that the SNCR temperature window often exists within the convective passes. Demonstrations at the Port Jefferson, Morro Bay, and Merrimac plants have shown that injecting in the convective pass can create high ammonia slip due to limited residence time at the operating temperatures of SNCR. Shore, D., et al, "Urea SNCR Demonstration at Long Island Lighting Company's Port Jefferson Station, Unit 3," Proceedings of the EPRI/EPA Joint Symposium on Stationary Combustion NOx Control, May 1993.' Lin, Chin-I, " Full Scale Tests of SNCR Technology on a Gas-Fired Boiler," EPRI Workshop on NO_X Controls for Utility Boilers, July 1992.

EPRI sponsored a computational fluid dynamics modeling program to evaluate the performance of SNCR on Southern Company Service's Wansley Unit 1 located in Roopville, Georgia. This 880-MW unit is a tangentially-fired boiler equipped with a low-NOX burner and separated overfire air. The modeling results demonstrated that SNCR has the potential to reduce NOx emissions by only 22% with an acceptable ammonia slip of 6 ppm. The firing characteristics of the boiler make achieving higher levels of NOx reduction impractical. The most influential factor is the separated overfire air system, which elevates upper furnace temperatures by causing the combustion process to extend beyond the furnace nose and into the convection section. Harmon, A., et al., "Evaluation of SNCR Performance on Large-Scale Coal-Fired Boilers," Institute of Clean Air Companies (ICAC) Forum on Cutting NOx Emissions, Durham, NC, March 1998.

emission rates demonstrated by all three Laramie River units, outlet emissions at 0.07 lb/mmBtu represent only a 62% - 68% SCR control efficiency.) WY DEQ has not provided any documentation or justification to support the higher emission rates used in its analyses. In other recent BART actions, EPA has determined that SCR can achieve 0.05 lb/mmBtu on an annual basis. Such an underestimate at Laramie River biases the cost-benefit analysis against SCR and is inconsistent with other EPA analyses.

WY DEQ has underestimated the cost of SNCR.

WY DEQ estimated LNB+OFA+SNCR would cost \$2,056 - \$2,109/ton. EPA R8 calculated the incremental costs of SCR versus LNB+OFA+SNCR, its preferred control option, and estimated incremental costs of \$7,054 - \$7,242/ ton. We are concerned that WY DEQ underestimated the cost of SNCR, which biases its emphasis on incremental costs against SCR. We calculated the costs of SNCR using the Control Cost Manual (CCM) (with the reagent correction[2] used by EPA R8 for Montana), used heat inputs and emission estimates from EPA's Clean Air Market (CAM) data for 2001 – 2003, and our results are presented in Table 1.a. below, and details can be found in Appendix LR.

[2] We corrected the error in the equation 1.15 for estimating reagent use in the EPA Control Cost Manual method for estimating SNCR costs as used by EPA R8 in its Colstrip analysis and based upon discussions with EPA R8 staff.

Table 1.a. LNB+OFA+SNCR Costs from OAQPS Control Cost Manual (CCM)

Unit	1	2	3	Data Source
Uncontrolled Emissions (tpy)	6,127	6,348	6,412	CCM
Uncontrolled Emissions (lb/mmBtu)	0.26	0.27	0.27	CAMD 2001 - 2003
Combustion Controls Cost-benefit Analysis				
Control Efficiency	12%	16%	14%	calculated
Controlled emissions (lb/mmBtu)	0.23	0.23	0.23	EPA FRN
Controlled Emissions (tpy)	5,384	5,354	5,493	calculated
Emissions Reduction (tpy)	744	994	919	calculated
Capital Cost	$ 22,096,000	$ 22,096,000	$ 22,096,000	WY DEQ
Capital Cost ($/kW)	$ 37	$ 37	$ 37	calculated
O&M Cost	$60,000	$60,000	$60,000	WY DEQ
Annualized Cost	$ 1,944,000	$ 1,944,000	$ 1,944,000	EPA FRN
Cost-Effectiveness ($/ton)	$ 2,614	$ 1,955	$ 2,115	calculated
SNCR Cost-benefit Analysis				
Control Efficiency	48%	48%	48%	CCM
Controlled emissions (lb/mmBtu)	0.12	0.12	0.12	NPS assumption
Emissions Reduction (tpy)	2,575	2,561	2,627	CCM
Capital Cost	$ 5,560,531	$ 5,489,560	$ 5,613,033	CCM
Capital Cost ($/kW)	$ 9	$ 9	$ 9	calculated
O&M Cost	$ 6,412,515	$ 6,377,353	$ 6,542,793	CCM
Annualized Cost	$ 7,020,798	$ 6,977,872	$ 7,156,819	CCM
Cost-Effectiveness ($/ton)	$ 2,727	$ 2,725	$ 2,724	CCM
Combustion Controls + SNCR Cost-benefit Analysis				
Control Efficiency	54.2%	56.0%	55.3%	calculated
Controlled Emissions (tpy)	2,809	2,793	2,866	calculated
Emissions Reduction (tpy)	3,319	3,555	3,546	calculated
Capital Cost	$ 27,656,531	$ 27,585,560	$ 27,709,033	calculated
Capital Cost ($/kW)	$ 47	$ 47	$ 47	calculated
O&M Cost	$ 6,472,515	$ 6,437,353	$ 6,602,793	calculated
Annualized Cost	$ 8,416,515	$ 8,381,353	$ 8,546,793	calculated
Cost-Effectiveness ($/ton)	$ 2,536	$ 2,358	$ 2,410	calculated

Based upon application of the CCM, we estimate SNCR cost-effectiveness at $2,358 - $2,536/ton, which is $300 - $400/ton higher than WY DEQ's estimates. We also applied EPA's IPM method for estimating SNCR costs and those results (Table 1.b. below) show even higher costs for SNCR, and details can be found in Appendix LR.

Table 1.b. LNB+OFA+SNCR Costs from IPM

Unit	1	2	3	
Uncontrolled Emissions (tpy)	6,127	6,348	6,412	CAMD 2001 - 2003
Uncontrolled Emissions (lb/mmBtu)	0.26	0.27	0.27	CAMD 2001 - 2003
Combustion Controls Cost-benefit Analysis				
Control Efficiency	12%	16%	14%	calculated
Controlled emissions (lb/mmBtu)	0.23	0.23	0.23	EPA FRN
Controlled Emissions (tpy)	5,384	5,354	5,493	calculated
Emissions Reduction (tpy)	744	994	919	calculated
Capital Cost	$ 22,096,000	$ 22,096,000	$ 22,096,000	WY DEQ
Capital Cost ($/kW)	$ 37	$ 37	$ 37	calculated
O&M Cost	$ 60,000.00	$ 60,000.00	$ 60,000.00	WY DEQ
Annualized Cost	$ 1,944,000	$ 1,944,000	$ 1,944,000	EPA FRN
Cost-Effectiveness ($/ton)	$ 2,614	$ 1,955	$ 2,115	calculated
SNCR Cost-benefit Analysis				
Control Efficiency	48%	48%	48%	calculated
Controlled emissions (lb/mmBtu)	0.12	0.12	0.12	NPS assumption
Emissions Reduction (tpy)	2,575	2,561	3,067	calculated
Capital Cost	$ 10,385,000	$ 10,321,000	$ 10,318,000	IPM
Capital Cost ($/kW)	$ 18	$ 17	$ 17	calculated
Capital Recovery Factor	0.0944	0.0944	0.0944	calculated for 20 years @ 7% interest
Annual Capital Cost	$ 980,271	$ 974,229	$ 973,946	calculated
O&M Cost	$ 7,817,408	$ 7,817,408	$ 8,020,206	IPM
Annualized Cost	$ 8,797,679	$ 8,791,638	$ 8,994,152	calculated
Cost-Effectiveness ($/ton)	$ 3,417	$ 3,433	$ 2,933	calculated
Combustion Controls + SNCR Cost-benefit Analysis				
Control Efficiency	54.2%	56.0%	55.3%	calculated
Controlled Emissions (tpy)	2,809	2,793	2,426	calculated
Emissions Reduction (tpy)	3,319	3,555	3,546	calculated
Capital Cost	$ 32,481,000	$ 32,417,000	$ 32,414,000	calculated
Capital Cost ($/kW)	$ 55	$ 55	$ 55	calculated
O&M Cost	$ 7,877,408	$ 7,877,408	$ 8,080,206	calculated
Annualized Cost	$ 9,821,408	$ 9,821,408	$ 10,024,206	calculated
Cost-Effectiveness ($/ton)	$ 2,960	$ 2,763	$ 2,827	calculated

WY DEQ has overestimated the cost of SCR.

Neither Basin Electric nor WY DEQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and Basin Electric and WY DEQ did not properly use the CCM. (For example, the cost estimates used by WY DEQ contained Owner's Costs and Allowance for Funds Utilized During Construction, which are not allowed by the CCM and have been rejected by EPA R8 in other analyses. The total for these improper costs exceeds $14 million per SCR.) As a result, we believe that capital and annual costs are overestimated.

In conducting our cost analysis of SCR at Laramie River, we used an approach similar to that used by EPA R8 in its evaluation of SCR on the Colstrip power plant. We used EPA's IPM model to estimate Direct Capital Cost (DCC) at $93 million.[3] Because Basin Electric's DCC cost was $84.5 million (after adjusting to 2010$), we used that instead of the IPM estimate for DCC. We then applied the EPA CCM factors (totaling 141%) for Indirect Capital Cost to estimate a Total Capital Investment (TCI) of $119 million ($202/kW) which is consistent with industry data, but lower than the WY DEQ estimate. Next, we applied the CCM methods for estimating Direct and Indirect Annual Costs to the TCI and arrived at a Total Annual Cost of $15.1 million for SCR versus $15.8 million by WY DEQ. We concluded that SCR for Unit 1 would remove 5,191 tpy and cost $2,916/ton (compared to 4,681 tpy removed at $3,372/ton estimated by WY DEQ). We estimated $2,800/ton cost-effectiveness for addition of SCR to Laramie River #2 and #3 in the same manner, and our results are shown in Table 2 and details can be found in Appendix LR.

Table 2. Cost-Effectiveness of SCR Laramie River from OAQPS Control Cost Manual (CCM)

Unit	1	2	3	
Uncontrolled Emissions (tpy)	6,127	6,348	6,412	CCM
Uncontrolled Emissions (lb/mmBtu)	0.26	0.27	0.27	CAMD 2001 - 2003
SCR Cost-benefit Analysis				
Control Efficiency	85%	85%	85%	CCM
Controlled emissions (lb/mmBtu)	0.04	0.04	0.04	NPS assumption
Controlled Emissions (tpy)	936	931	955	calculated
Emissions Reduction (tpy)	5,191	5,417	5,457	CCM
Capital Cost	$ 119,096,149	$ 119,102,425	$ 119,101,952	calculated
Capital Cost ($/kW)	$ 202	$ 201	$ 202	calculated
O&M Cost	$ 3,894,273	$ 3,934,070	$ 3,979,393	CCM
Annualized Cost	$ 15,136,107	$ 15,176,497	$ 15,221,775	CCM
Cost-Effectiveness ($/ton)	$ 2,916	$ 2,802	$ 2,789	CCM

Even taken at face value, the $3,300 - $3,400 cost/ton estimates by WY DEQ for SCR are similar to or lower than the cost/ton values accepted as reasonable in other BART analyses.

EPA R8 has placed undue weight on incremental costs.

Even though Basin and WY DEQ have overestimated the cost of SCR, WY DEQ determined that "the cost effectiveness and incremental cost effectiveness of the proposed BART technologies for NO_X are all reasonable." However, EPA R8 has essentially based its BART determination on incremental costs and incremental benefits. For example, EPA R8 has determined that the incremental costs of adding SNCR to LNB+OFA are reasonable, but SCR is not:

- Unit 1: Incremental cost effectiveness for the controls evaluated is as follows: LNBs with OFA and SNCR: $2,105/ton, and SCR: $7,198/ton.Unit 2:

[3] after adjusting to 2010$ using the CEPCI

> Incremental cost effectiveness for the controls evaluated is as follows: LNBs with OFA and SNCR: $2,117/ton; and SCR: $7,242/ton.Unit 3: Incremental cost effectiveness for the controls evaluated is as follows: LNBs with OFA and SNCR: $2,064/ton, and SCR: $7,054/ton

Our analysis (Tables 3.a. and 3.b.) below shows that EPA R8 has underestimated the incremental costs of its preferred SNCR option and overestimated the incremental costs of the SCR option rejected by EPA R8.

Table 3.a. Incremental Costs and Benefits of LNB+OFA+SNCR vs. LNB+OFA

Unit	1	2	3
Combustion Controls Cost-benefit Analysis			
Emissions Reduction (tpy)	744	994	919
Annualized Cost	$ 1,944,000	$ 1,944,000	$ 1,944,000
Combustion Controls + SNCR Cost-benefit Analysis			
Emissions Reduction (tpy)	3,319	3,555	3,546
Annualized Cost	$ 8,416,515	$ 8,381,353	$ 8,546,793
Incremental Cost-benefit Analysis			
Emissions Reduction (tpy)	2,575	2,561	2,627
Annualized Cost	$ 6,472,515	$ 6,437,353	$ 6,602,793
Cost-Effectiveness ($/ton)	$ 2,514	$ 2,514	$ 2,513

Table 4.b. Incremental Costs and Benefits of SCR vs. LNB+OFA

Unit	1	2	3
Combustion Controls Cost-benefit Analysis			
Emissions Reduction (tpy)	744	994	919
Annualized Cost	$ 1,944,000	$ 1,944,000	$ 1,944,000
SCR Cost-benefit Analysis			
Emissions Reduction (tpy)	5,191	5,417	5,457
Annualized Cost	$ 15,136,107	$ 15,176,497	$ 15,221,775
Incremental Cost-benefit Analysis			
Emissions Reduction (tpy)	4,447	4,423	4,538
Annualized Cost	$ 13,192,107	$ 13,232,497	$ 13,277,775
Cost-Effectiveness ($/ton)	$ 2,966	$ 2,992	$ 2,926

Furthermore, a comparison of the SCR to EPA R8's preferred LNB+OFA+SNCR option (Table 3.c.) shows incremental costs less than $4,000/ton which are well below values EPA typically accepts. For example, in its proposal to disapprove part of the North Dakota plan, EPA R8 cited the "…relatively low incremental cost effectiveness between the two control options ($4,855 per ton)…"

Table 3.c. Incremental Costs and Benefits of SCR vs. LNB+OFA+SNCR

Unit	1	2	3
Combustion Controls + SNCR Cost-benefit Analysis			
Emissions Reduction (tpy)	3,319	3,555	3,546
Annualized Cost	$ 8,416,515	$ 8,381,353	$ 8,546,793
SCR Cost-benefit Analysis			
Emissions Reduction (tpy)	5,191	5,417	5,457
Annualized Cost	$ 15,136,107	$ 15,176,497	$ 15,221,775
Incremental Cost-benefit Analysis			
Emissions Reduction (tpy)	1,873	1,862	1,911
Annualized Cost	$ 6,719,592	$ 6,795,143	$ 6,674,982
Cost-Effectiveness ($/ton)	$ 3,588	$ 3,649	$ 3,494

For Laramie River, the NPS estimates of incremental costs of SCR are only slightly greater than SCR's average costs, which are reasonable when compared to costs accepted by other states and EPA.

EPA R8 has incorrectly estimated visibility improvement from all NO_X control options.

WY DEQ evaluated visibility improvements at the two nearest Class I areas and reported the "The cumulative visibility improvement for SCR, as compared to LNB/OFA, across Wind Cave NP and Badlands NP (based on the 98th percentile modeled results) was 0.52-0.54 Δdv for each of the three units." EPA R8 evaluated the five closest Class I areas but reported results for only the Wind Cave NP.

Conclusions

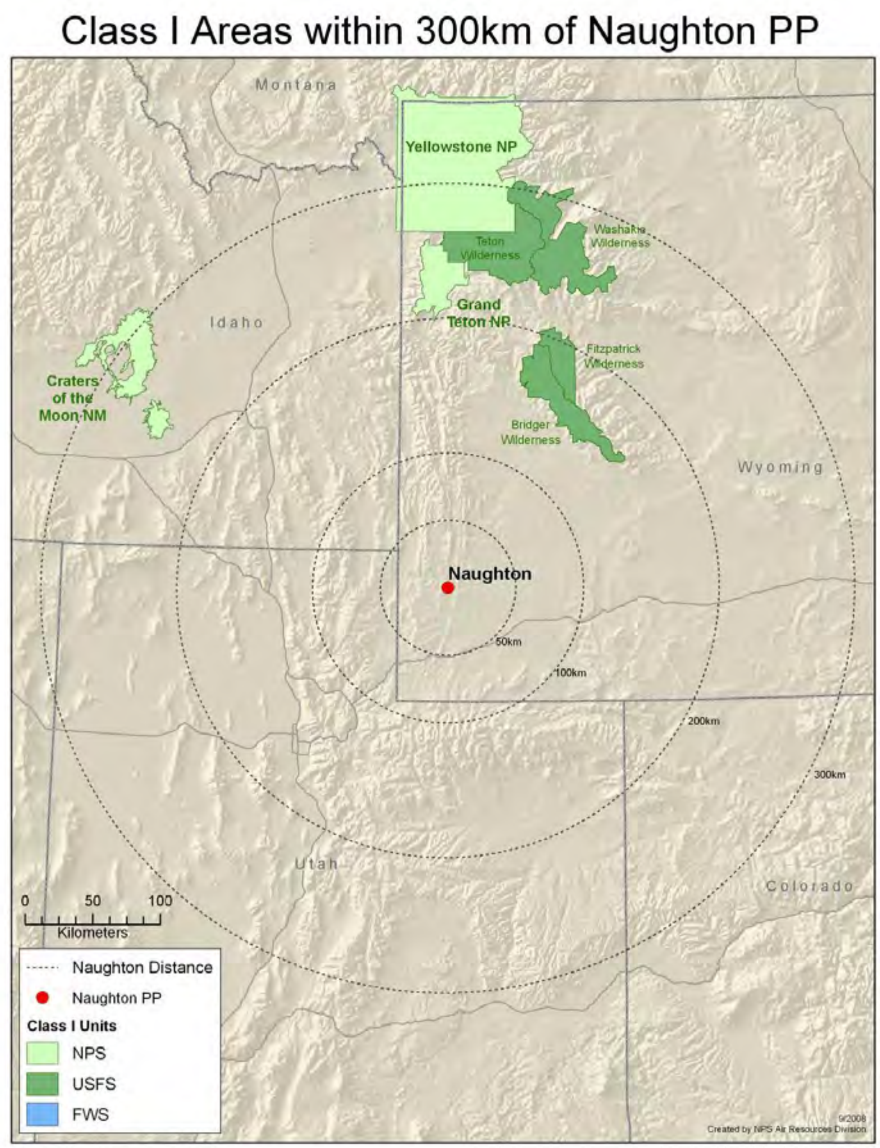
- WY DEQ has overestimated the ability of Selective Non-Catalytic Reduction (SNCR) to reduce emissions.
- WY DEQ has underestimated the ability of Selective Catalytic Reduction (SCR) to reduce emissions.
- WY DEQ has underestimated the cost of SNCR.
- WY DEQ has overestimated the cost of SCR.
- EPA R8 has placed undue weight on incremental costs.
- EPA R8 has incorrectly estimated visibility improvement from all NO_X control options.
- EPA R8 did not consider cumulative benefits of improving visibility at multiple Class I areas.

For the numerous reasons cited above, we have significant concerns with EPA R8's BART analysis for Laramie River. We believe that addition of SCR is BART for all three units at Laramie River.

National Park Service (NPS) Comments on EPA Region 8's proposed Best Available Retrofit Technology (BART) Determination for Naughton Power Plant August 3, 2012

Facility Background

PacifiCorp's Naughton Power Plant (Naughton) is comprised of three tangentially-fired units burning sub-bituminous coals with a total gross generating capacity of 770 megawatts (MW).[1] According to EPA's Clean Air Markets (CAM) database, 2011 NO_x emissions from Naughton were 13,898 tons which ranked the plant #24 in the U.S. There are seven Class I areas within 300 km of Naughton:



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[1] Based on EPA's Clean Air Markets data for 2001 – 2003. Data for 2008 – 2011 show that Naughton units continued to generate in excess of 750 MW when individual unit maxima are summed.

Naughton Unit 1 commenced operation in 1963 and can generate at least 174 MW. It was originally constructed with a Research Cottrell mechanical dust collector to control particulate matter emissions, and in 1974 a Lodge Cottrell electrostatic precipitator (ESP) was added to further reduce particulate emissions. SO_2 and NO_X emissions are uncontrolled. 2011 NO_x emissions were 3,979 tons which ranked the EGU #113 in the U.S.

Naughton Unit 2 commenced operation in 1968 and can generate at least 229 MW. It was originally constructed with a United Conveyor mechanical dust collector to control particulate matter emissions and in 1976 a Lodge Cottrell ESP was added to further reduce particulate emissions. SO_2 and NO_X emissions are uncontrolled. 2011 NO_x emissions were 4,921 tons which ranked the EGU #97 in the U.S.

Naughton Unit 3 commenced operation in 1971 and can generate at least 369 MW. The unit was retrofitted with ALSTOM LCCFS II Low-NO_x Burners (LNB) in 1999. Particulate emissions are controlled using a Buell weighted wire ESP and Flue Gas Conditioning (FGC). SO_2 emissions are controlled using low sulfur coal and a UOP LLC two-tower sodium-based wet flue gas desulfurization system that was installed in 1997. 2011 NO_x emissions were 5,628 tons which ranked the EGU #47 in the U.S.

PacifiCorp recently received an air quality permit to modify the three Naughton units. Units 1 and 2 will be equipped with new state-of-the-art LNB systems with advanced Overfire Air (OFA) and FGC systems to help improve the particulate removal efficiency of the existing ESPs on each of the units. New WFGD systems will be installed on Naughton Units 1 and 2. The existing ESP on Naughton Unit 3 will be replaced with a new full-scale fabric filter at which time the existing FGC system will be removed.

BART Analysis for NO_x

The presumptive NO_X BART limit for a plant with capacity greater than 750 MW and burning sub-bituminous coal in a tangentially-fired boiler is 0.15 lb/mmBtu. For the Naughton units burning a combination of the Bridger, Black Butte, and Leucite Hill coals, PacifiCorp contends that actual data demonstrate the likely NO_X emission rate will be closer to the bituminous (0.28 lb/mmBtu) BART presumptive NO_X limit. However, documents submitted by PacifiCorp state:

> As shown in Table 1, although Bridger, Black Butte, Leucite Hills, and Naughton are classified as subbituminous, they all exhibit higher nitrogen content, lower moisture content, and lower oxygen content than the PRB coal.[2]
>
> Coals at Naughton are typically ranked as Sub-Bituminous "B".[3]

[2] T E C H N I C A L M E M O R A N D U M, Coal Quality and Nitrogen Oxide Formation, PREPARED FOR: Bill Lawson/PacifiCorp, PREPARED BY: CH2M HILL, COPIES: Mike Jenkins/PacifiCorp, DATE: January 28, 2009

We believe that the burden is on PacifiCorp to show that the lower (0.15 lb/mmBtu) presumptive BART limit does not apply to these tangentially-fired boilers burning sub-bituminous coals.

WY DEQ has underestimated the ability of SCR to reduce emissions.

In estimating the annual cost-effectiveness of the LNB+OFA+SCR option, WY DEQ assumed 0.07 lb/mmBtu on an annual average basis. Based on the 0.026 - 0.37 lb/mmBtu NO_X emission rate predicted for the combustion control option, outlet emissions at 0.07 lb/mmBtu represent only 73% - 81% SCR control efficiency as opposed to the generally-accepted 90%. In other recent BART actions, EPA has determined that SCR can achieve 0.05 lb/mmBtu on an annual basis. Such an underestimate at Naughton biases the cost-benefit analysis against SCR and is inconsistent with other EPA analyses.

WY DEQ has overestimated the annual cost of SCR.

Figure 3 of a survey of industry SCR cost data (conducted for the Utility Air Regulatory Group and included in Appendix A) and EPA Integrated Planning Model (IPM) estimates show that typical SCR costs for units the size of the Naughton units would be $280 - $330/kW.[4] WY DEQ's cost estimates for SCR are $412 - $531/kW, which exceed real-world industry costs ($50 - $300/kW) and industry estimates, leading us to believe that capital and annual costs are overestimated. Neither PacifiCorp nor WY DEQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and PacifiCorp and WY DEQ did not use the Control Cost Manual (CCM). (For example, the cost estimates[5] used by WY DEQ contained Allowance for Funds Utilized During Construction which is not allowed by the CCM and has been rejected by EPA R8 in other analyses. The total for these improper costs exceeds $17 million.)

In conducting our cost analysis of SCR at Naughton, we used an approach similar to that used by EPA R8 in its evaluation of SCR on the Colstrip power plant. For Naughton Unit 1, we used EPA's IPM model to estimate Direct Capital Cost (DCC) at $33 million.[6] We then applied the CCM factors (totaling 141%) for Indirect Capital Cost to estimate a Total Capital Investment (TCI) of $46 million ($266/kW) which is consistent with industry data, but much lower than the WY DEQ estimate ($531/kW). Next, we applied the CCM methods for estimating Direct and Indirect Annual Costs to the TCI and arrived at a Total Annual Cost of $6.8 million for LNB+OFA+SCR versus $10.2 million by WY

[3] NOx VARIATION WITH WESTERN U.S. SOURCED COALS FIRED IN PACIFICORP UTILITY BOILERS ALSTOM, Inc., Windsor, CT, February 4, 2005

[4] "OVERVIEW OF INFORMATION ON PROJECTED CONTROL TECHNOLOGY COSTS AND PERFORMANCE AS DEVELOPED FOR EPA'S INTEGRATED PLANNING MODEL (IPM)" October 15, 2010, Prepared by J. Edward Cichanowicz for the Utility Air Regulatory Group

[5] "Best Available Retrofit Technology Modeling Refinements" July 24, 2008

[6] after adjusting to 2010$ using the CEPCI

DEQ. We concluded that LNB+OFA+SCR for Unit 1 would remove 3,249 tpy and cost $2,098/ton (compared to 3,720 tpy removed at $2,750/ton estimated by WY DEQ).

We estimated $8.2 and $11.4 million Total Annual Costs for addition of SCR to Naughton Units 2 and 3, respectively, in the same manner, and estimated $2,037 and $2,844/ton cost-effectiveness for addition of SCR to Naughton Units 2 and 3 (compared to $2,848 and $2,830/ton estimated by WY DEQ).

Our results are shown in Table 1 and details can be found in Appendix EN.

Table 1. NPS estimates of LNB+OFA+SCR costs for Naughton

Unit	Unit #1	Unit #2	Unit #3
Uncontrolled Emissions (tpy)	3,594	4,431	4,623
Uncontrolled Emissions (lb/mmBtu)	0.52	0.53	0.37
Combustion Controls Cost-benefit Analysis			
Control Efficiency	50%	51%	1%
Controlled emissions (lb/mmBtu)	0.26	0.26	0.37
Controlled Emissions (tpy)	1,792	2,160	4,598
Emissions Reduction (tpy)	1,801	2,271	24
Capital Cost	$ 9,600,000	$ 9,100,000	$ 1,000,000
Capital Cost ($/kW)	$ 55	$ 40	$ 3
Annualized Cost	$ 993,248	$ 945,683	$ 95,130
Cost-Effectiveness ($/ton)	$ 551	$ 416	$ 3,910
SCR Cost-benefit Analysis			
Control Efficiency	81%	81%	86%
Controlled emissions (lb/mmBtu)	0.05	0.05	0.05
Emissions Reduction (tpy)	1,448	1,745	3,977
Capital Cost	$ 46,178,292	$ 58,126,358	$ 88,264,275
Capital Cost ($/kW)	$ 266	$ 254	$ 239
O&M Cost	$ 1,464,542	$ 1,748,214	$ 2,954,139
Annualized Cost	$ 5,823,446	$ 7,234,931	$ 11,285,662
Cost-Effectiveness ($/ton)	$ 4,023	$ 4,147	$ 2,838
Combustion Controls + SCR Cost-benefit Analysis			
Control Efficiency	90.4%	90.6%	86.6%
Controlled Emissions (tpy)	345	415	621
Emissions Reduction (tpy)	3,249	4,016	4,001
Capital Cost	$ 55,778,292	$ 67,226,358	$ 89,264,275
Capital Cost ($/kW)	$ 321	$ 293	$ 242
O&M Cost	$ 1,464,542	$ 1,748,214	$ 2,954,139
Annualized Cost	$ 6,816,694	$ 8,180,614	$ 11,380,792
Cost-Effectiveness ($/ton)	$ 2,098	$ 2,037	$ 2,844

Even taken at face value, the $2,750 and $2,848 costs per ton estimated by WY DEQ for LNB+OFA+ SCR on Naughton Units # 1 and 2, respectively, are similar to or lower than the cost/ton values accepted as reasonable in other BART analyses, including WY DEQ's and EPA R8's conclusion that addition of OFA+SCR at $2,830/ton is reasonable for Naughton Unit #3.

EPA R8 has placed undue weight on incremental costs.

Even though PacifiCorp and WY DEQ have overestimated the cost of SCR, WY DEQ determined that "the cost effectiveness and incremental cost effectiveness of the proposed BART technologies for NO_X are all reasonable." However, EPA R8 has essentially based its BART determination on incremental costs and incremental benefits. For example, EPA R8 has determined that the incremental costs of adding SCR (versus SNCR) to LNB+OFA are not reasonable:

- (Unit 1) Incremental cost effectiveness for the controls evaluated are LNBs with OFA and SCR: $8,089/ton.
- (Unit 2) Incremental cost effectiveness for the controls evaluated are LNBs with OFA and SCR: $7,852/ton.
- (Unit 3) Incremental cost effectiveness for the controls evaluated are LNBs with OFA and SCR: $4,105.

In order to properly evaluate incremental cost differentials, it is essential that the costs being compared be calculated correctly. We calculated the costs of SNCR using the CCM (with the reagent correction[7] used by EPA R8 for Montana) and our results are presented in Table 2 below, and details can be found in Appendix EN.

[7] We corrected the error in the equation 1.15 for estimating reagent use in the EPA Control Cost Manual method for estimating SNCR costs as used by EPA R8 in its Colstrip analysis and based upon discussions with EPA R8 staff.

Table 2. LNB+OFA+SNCR Costs from OAQPS Control Cost Manual (CCM)

Unit	1	2	3	Data Source
Uncontrolled Emissions (tpy)	3,594	4,431	4,623	CCM
Uncontrolled Emissions (lb/mmBtu)	0.52	0.53	0.37	CAMD 2001 - 2003
Combustion Controls Cost-benefit Analysis				
Control Efficiency	50%	51%	30%	calculated
Controlled emissions (lb/mmBtu)	0.26	0.26	0.26	EPA FRN
Controlled Emissions (tpy)	1,792	2,160	3,231	calculated
Emissions Reduction (tpy)	1,801	2,271	1,391	calculated
Capital Cost	$ 9,600,000	$ 9,600,000	$ 9,600,000	WY DEQ
Capital Cost ($/kW)	$ 55	$ 42	$ 42	calculated
O&M Cost	$60,000	$60,000	$60,000	WY DEQ
Annualized Cost	$ 993,248	$ 993,248	$ 993,248	EPA FRN
Cost-Effectiveness ($/ton)	$ 551	$ 437	$ 714	calculated
SNCR Cost-benefit Analysis				
Control Efficiency	19%	19%	19%	CCM
Controlled emissions (lb/mmBtu)	0.21	0.21	0.21	NPS assumption
Emissions Reduction (tpy)	345	415	621	CCM
Capital Cost	$ 2,422,935	$ 2,709,600	$ 4,636,423	CCM
Capital Cost ($/kW)	$ 14	$ 12	$ 20	calculated
O&M Cost	$ 803,978	$ 968,963	$ 1,449,463	CCM
Annualized Cost	$ 1,069,030	$ 1,265,374	$ 1,956,655	CCM
Cost-Effectiveness ($/ton)	$ 3,102	$ 3,046	$ 3,149	CCM
Combustion Controls + SNCR Cost-benefit Analysis				
Control Efficiency	59.7%	60.6%	43.5%	calculated
Controlled Emissions (tpy)	1,448	1,745	2,610	calculated
Emissions Reduction (tpy)	2,146	2,686	2,013	calculated
Capital Cost	$ 12,022,935	$ 12,309,600	$ 14,236,423	calculated
Capital Cost ($/kW)	$ 69	$ 54	$ 62	calculated
O&M Cost	$ 863,978	$ 1,028,963	$ 1,509,463	calculated
Annualized Cost	$ 1,857,226	$ 2,022,211	$ 2,502,711	calculated
Cost-Effectiveness ($/ton)	$ 865	$ 753	$ 1,243	calculated

Our analysis (Table 3) below shows that EPA R8 has overestimated the incremental costs of the SCR option rejected by WY DEQ.

Table 3: Incremental Costs and Benefits of SCR vs. LNB+OFA

Unit	Unit #1	Unit #2	Unit #3
Combustion Controls + SNCR Cost-benefit Analysis			
Emissions Reduction (tpy)	2,146	2,686	2,013
Total Annual Cost	$ 1,857,226	$ 2,022,211	$ 2,502,711
Combustion Controls + SCR Cost-benefit Analysis			
Emissions Reduction (tpy)	3,249	4,016	4,001
Annualized Cost	$ 6,816,694	$ 8,180,614	$ 11,380,792
Combustion Controls+SCR Incremental Cost-Effectiveness			
Incremental Emissions Reduction (tpy)	1,103	1,329	1,989
Incremental Annualized Cost	$ 4,959,468	$ 6,158,403	$ 8,878,081
Incremental Cost-Effectiveness ($/ton)	$ 4,496	$ 4,633	$ 4,465

Our evaluation of incremental costs conducted using methods accepted by EPA R8 in other analyses shows that there is little difference in the incremental costs of adding SCR to Units 1 and 2 versus Unit #3, and that all incremental costs are reasonable. For example, in its proposal to disapprove part of the North Dakota plan, EPA R8 cited the "…relatively low incremental cost effectiveness between the two control options ($4,855 per ton)…" For Naughton, the NPS estimates of incremental costs of SCR are only slightly greater than SCR's average costs, which are reasonable when compared to costs accepted by other states and EPA.

EPA R8 has incorrectly estimated visibility improvement from all NO_X control options. (Please see our general comments.)

EPA R8 has underestimated visibility improvement from SCR. (Please see our general comments.)

Despite our concerns with the visibility modeling conducted by EPA R8, taken at face value, the annual costs and visibility improvements (presented by EPA R8) associated with addition of SCR result in cost-effectiveness of $9.6 million/dv for Naughton Unit 1, $11.5 million/dv for Unit 2, and $15.7 million/dv for Unit 3 (which EPA R8 deemed reasonable) at the nearest Class I area. All three of these estimates are below or within the range of average cost/dv accepted as "reasonable" across the US (and by PacifiCorp).

<u>Conclusions</u>

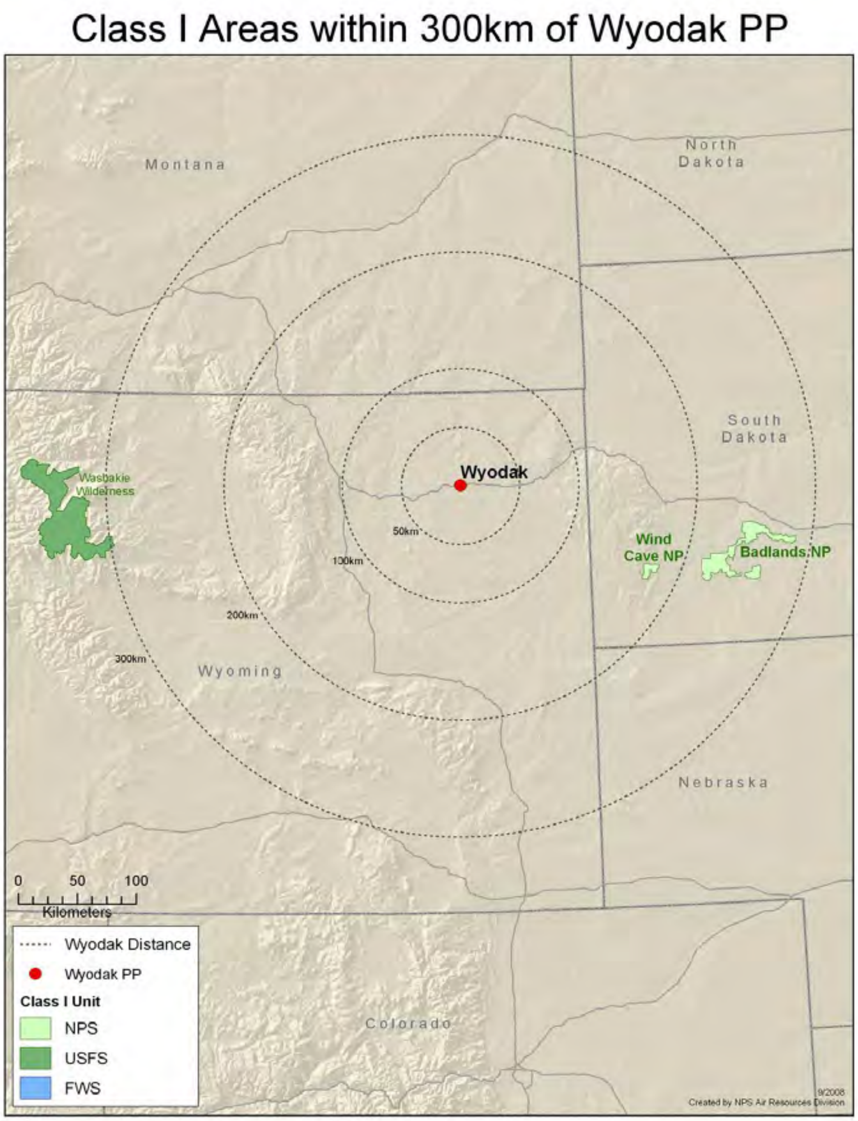
- WY DEQ has underestimated the ability of SCR to reduce emissions.
- WY DEQ has overestimated the cost of SCR.
- EPA R8 has incorrectly estimated incremental cost-effectiveness of adding SCR versus SNCR and placed undue weight on its incremental cost-effectiveness results.
- EPA R8 has incorrectly estimated visibility improvement from all NO_X control options.
- EPA R8 did not consider cumulative benefits of improving visibility at multiple Class I areas.
- EPA R8's 0.26 lb/mmBtu proposal does not meet presumptive NO_X BART for Units1 and 2.

For the reasons cited above, we disagree with EPA R8's BART analysis and determination for Naughton. However, taken at face value, the annual costs and visibility improvements associated with addition of SCR result in cost-effectiveness (in $/dv) estimates that are accepted as "reasonable" and would indicate that SCR is BART for all three units. We agree with EPA R8 that SCR represents BART for Unit 3, but recommend a lower 30-day rolling average emission limit (e.g. 0.06 lb/mmBtu) to reflect the true capabilities of SCR.

National Park Service (NPS) Comments on EPA Region 8's proposed Best Available Retrofit Technology (BART) Determination for the Wyodak Power Plant August 3, 2012

<u>Facility Background</u>

PacifiCorp's Wyodak Power Plant is comprised of one dry-bottom wall-fired EGU burning pulverized sub-bituminous Powder River Basin coal with a gross generating capacity of (at least) 395 megawatts (MW) based upon 2001 - 2003 data from EPA's Clean Air Markets (CAM) database. Although presumptive BART does not apply to this power plant with less than 750 MW capacity, the presumptive NO_X limit for this EGU is 0.23 lb/mmBtu. According the CAM database, 2011 NO_x emissions from Wyodak were 2,409 tons which ranked the plant #225 in the U.S. There are three Class I areas within 300 km of Wyodak:



Wyodak's EGU was manufactured by Babcock & Wilcox and commenced service in 1978. NO_X emissions from the boiler are currently controlled with Alstom TFS 2000® Low-NOx Burner (LNB) Technology w/Overfire Air (OFA) which began Apr 18, 2011. PM emissions were controlled using an electrostatic precipitator until Apr 18, 2011 when it was replaced by a fabric filter. SO_2 emissions are controlled using a Joy Niro, three-tower lime-based spray dryer installed in 1986.

BART Analysis for NO_x

WY DEQ has underestimated the ability of SCR to reduce emissions.

In estimating the annual cost-effectiveness of the LNB+OFA+SCR option, WY DEQ assumed 0.07 lb/mmBtu on an annual average basis. Based on the 0.18 lb/mmBtu NO_X emission rate predicted for the LNB+OFA option, outlet emissions at 0.07 lb/mmBtu represent only a 61% SCR control efficiency as opposed to the generally-accepted 90%. WY DEQ has not provided any documentation or justification to support the higher emission rates used in its analyses. In other recent BART actions, EPA has determined that SCR can achieve 0.05 lb/mmBtu on an annual basis. Such an underestimate at Wyodak biases the cost-benefit analysis against SCR and is inconsistent with other EPA analyses.

WY DEQ has overestimated the cost of SCR.

Figure 3 of a survey of industry SCR cost data (included in Appendix A) and EPA Integrated Planning Model (IPM) estimates show that typical SCR costs for units the size of Wyodak would be \$180 - \$280/kW.[1] WY DEQ's cost estimates for SCR are \$474/kW, which exceed real-world industry costs (\$50 - \$300/kW) and industry estimates, leading us to believe that capital and annual costs are overestimated. Neither PacifiCorp nor WY DEQ provided justification or documentation for their cost estimates. We were not provided with any vendor estimates or bids, and PacifiCorp and WY DEQ did not use the Control Cost Manual (CCM). (For example, the cost estimates used by WY DEQ contained Allowance for Funds Utilized During Construction, which is not allowed by the CCM and has been rejected by EPA R8 in other analyses. The total for these improper costs exceeds \$8 million.) As a result, we believe that capital and annual costs are overestimated.

In conducting our cost analysis of SCR at Wyodak, we used an approach similar to that used by EPA R8 in its evaluation of SCR on the Colstrip power plant. We used EPA's IPM model to estimate Direct Capital Cost (DCC) at \$65 million.[2] We then applied the CCM factors (totaling 141%) for Indirect Capital Cost to estimate a Total Capital Investment (TCI) of \$91 million (\$231/kW) which is consistent with industry data, but much less than the WY DEQ estimate. Next, we applied the CCM methods for estimating

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[1] "OVERVIEW OF INFORMATION ON PROJECTED CONTROL TECHNOLOGY COSTS AND PERFORMANCE AS DEVELOPED FOR EPA'S INTEGRATED PLANNING MODEL (IPM)" October 15, 2010, Prepared by J. Edward Cichanowicz for the Utility Air Regulatory Group

[2] after adjusting to 2010\$ using the CEPCI

Direct and Indirect Annual Costs to the TCI and arrived at a Total Annual Cost of $13.1 million for LNB+OFA+SCR versus $18.9 million by WY DEQ. We concluded that LNB+OFA+SCR would remove 3,773 tpy and cost $3,475/ton (compared to 4,447 tpy removed at $4,252/ton estimated by WY DEQ). Our results are shown in Table 1 and details can be found in Appendix WY.

Table 1. NPS estimates of LNB+OFA+SCR costs for Wyodak

Uncontrolled Emissions (tpy)	4,653	OAQPS Control Cost Manual
Uncontrolled Emissions (lb/mmBtu)	0.26	CAMD 2001 - 2003
Combustion Controls Cost-benefit Analysis		
Control Efficiency	13%	calculated
Controlled emissions (lb/mmBtu)	0.23	EPA FRN
Controlled Emissions (tpy)	4,048	calculated
Emissions Reduction (tpy)	605	calculated
Capital Cost	$ 13,100,000	WY DEQ
Capital Cost ($/kW)	$ 33	calculated
O&M Cost	$60,000	WY DEQ
Annualized Cost	$ 1,306,203	EPA FRN
Cost-Effectiveness ($/ton)	$ 2,159	calculated
SCR Cost-benefit Analysis		
Control Efficiency	78%	OAQPS Control Cost Manual
Controlled emissions (lb/mmBtu)	0.05	NPS assumption
Emissions Reduction (tpy)	3,168	OAQPS Control Cost Manual
Capital Cost	$ 91,435,117	calculated
Capital Cost ($/kW)	$ 231	calculated
O&M Cost	$ 3,175,187	OAQPS Control Cost Manual
Annualized Cost	$ 11,806,015	OAQPS Control Cost Manual
Cost-Effectiveness ($/ton)	$ 3,726	OAQPS Control Cost Manual
Combustion Controls + SCR Cost-benefit Analysis		
Control Efficiency	81.1%	calculated
Controlled Emissions (tpy)	880	calculated
Emissions Reduction (tpy)	3,773	calculated
Capital Cost	$ 104,535,117	calculated
Capital Cost ($/kW)	$ 265	calculated
O&M Cost	$ 3,235,187	calculated
Annualized Cost	$ 13,112,218	calculated
Cost-Effectiveness ($/ton)	$ 3,475	calculated

Even taken at face value, the $4,252 cost/ton estimate by WY DEQ for SCR is lower than the cost/ton values accepted as reasonable in other BART analyses.

EPA R8 has placed undue weight on incremental costs and incremental benefits.

EPA R8 states, "Incremental cost effectiveness for the controls evaluated is…LNBs with OFA and SCR: $8,147/ton." Our analysis (above) of the LNB+OFA+SCR option shows an incremental cost of $3,726/ton for adding SCR to LNB+OFA. For comparison, in its proposal to disapprove part of the North Dakota plan, EPA R8 cited the "…relatively low incremental cost effectiveness between the two control options ($4,855 per ton)…"

Our estimates of incremental costs of SCR are only slightly greater than LNB+OFA+SCR's average costs, which are reasonable when compared to costs accepted by other states and EPA.

EPA R8 has incorrectly estimated visibility improvement from all NO_X control options.

(Please see our general comments.) WY DEQ evaluated cumulative visibility improvements at the two nearest Class I areas (Wind Cave and Badlands National Parks) while EPA R8 reported results for only one Class I area.

EPA R8 has underestimated visibility improvement from SCR.

(Please see our general comments.)

By overestimating costs of SCR and underestimating control efficiency and visibility benefits, EPA R8 recommended SNCR rather than SCR as BART.

Conclusions

- WY DEQ has underestimated the ability of Selective Catalytic Reduction (SCR) to reduce emissions.
- WY DEQ has overestimated the cost of SCR.
- EPA R8 has placed undue weight on its incremental cost-effectiveness results.
- EPA R8 has incorrectly estimated visibility improvement from all NO_X control options.
- EPA R8 did not consider cumulative benefits of improving visibility at multiple Class I areas.

For the reasons cited above, EPA R8's BART analysis for Wyodak is not acceptable. We believe that a proper BART analysis would conclude that addition of SCR is BART for Wyodak.