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

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IN REPLY REFER TO:

December 1, 2010

N3615 (2350)

Mr. Paul Tourangeau
Director, Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South
Denver, Colorado 80246-1530

Dear ~~Mr. Tourange~~au: Paul

In August and September 2010, the National Park Service and Fish and Wildlife Service received Colorado's draft determinations of Best Available Retrofit Technology (BART) and draft regional haze state implementation plan for review. We provided comments on November 15, 2010, on the BART determinations that were considered by the Colorado Air Pollution Control Commission at the meeting on November 18 and 19, 2010. Enclosed with this letter are our comments on the Craig Power Plant BART and reasonable progress determinations that will be considered by the Commission at the meeting on December 16, 2010. We will provide comments on the remaining Reasonable Progress and Alternative to BART determinations prior to the December 16, 2010 meeting.

We recommend that the Colorado Department of Public Health and Environment (CDPHE) determine Selective Catalytic Reduction (SCR) control technology as BART for Craig Units 1 and 2 and as reasonable progress for Craig Unit 3. Based on the installation and operation of SCR controls at electric utilities across the country, we believe that Tri-State and CDPHE under estimated the efficiency of SCR to reduce NOx emissions and significantly over estimated the costs to install SCR at Craig Units 1-3. In the enclosed documents we provide evidence to support our conservative cost estimate for installing SCR at Craig Units 1-3 in the range of \$3400 to \$3700/ton. These costs are well within the acceptable range set by CDPHE. The benefits of SCR for all three units at Craig for Mt. Zirkel Wilderness alone would be 2.8 dv. The benefits to visibility at other Class I areas in Colorado and the collateral benefits for reduced ozone and nitrogen deposition justify SCR at Craig.

We appreciate the opportunity to work closely with the Colorado Air Pollution Control Division on the development and review of your plans to improve visibility in our Class I national parks and wilderness areas. For further information regarding our comments, please contact Pat Brewer at (303) 969-2153.

Sincerely,

John Bunyak

John Bunyak
Acting Chief, Air Resources Division

Enclosure

cc:
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8OC-EISC
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NPS General Comments on CDPHE BART Analyses
December 1, 2010

As with any new program, much has been learned, and much is left to learn by all parties involved, and we are pleased to share the information we have obtained from our reviews of BART proposals across the nation. Following are our general comments on the five-step BART analyses conducted by CDPHE.

Step 1: "Identify All Available Technologies" and Step 2: "Eliminate Technically Infeasible Options" were generally comprehensive and well supported.

<u>Step 3: Evaluate Control Effectiveness of Each Remaining Technology</u>

Effectiveness of Selective Catalytic Reduction (SCR)

A common problem was an underestimation of the effectiveness of SCR to reduce emissions. SCR is different from many other control technologies in that its efficiency is not highly dependent upon the concentration of the pollutant to be controlled.[1] Instead, SCR efficiency is primarily influenced by the design of the catalyst reactor, that is, the volume of the catalyst, its cross-sectional area, number of layers, and measures to prevent blinding and deactivation, as well as replacement schedule. If it is necessary to achieve a high degree of removal efficiency on an inlet stream with a low concentration, more catalyst can be included in the design. It is generally understood that NO_X reductions of approximately 90% or more may be achieved with SCR systems.[2] And, according to the June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO_2 and NO_X Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier, "An excellent example of the significant investment many utilities have made over the past decade is American Electric Power (AEP), one of the largest public utilities in the U.S. with 39,000 MW of installed capacity with 69% of that capacity coal-fired. AEP is under a New Source Review (NSR) consent decree signed in 2007 that requires the utility install air quality control systems to reduce NO_X by 90%..."

We are aware of vendor guarantees of 0.05 lb/mmBtu,[3] and understand that major vendors are designing SCR systems to achieve 0.02 lb/mmBtu[4] on coal-fired boilers.

Operational evidence from SCR retrofits on eastern EGUs (see **Appendix A for "EGUs less**

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

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

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

[3] Minnesota Power Taconite Harbor BART analysis.

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

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

<u>Step 4: Evaluate Impacts and Document Results</u>

<u>Non-Air Quality Environmental Impacts</u>

According to the Institute for Clean Air Companies, ammonia can be handled safely.[5] Our discussions with SNCR vendors indicate that the concern about ash salability is likely unfounded.

<u>Cost of Compliance</u>

SCR Cost Estimation Methods

The SCR cost estimates submitted by Colorado BART sources are severely lacking in the types of specific information needed to give them credibility. Although there are several methods for estimating SCR costs, our experience leads us to believe that no one method is perfect and that the costing methods need to be tempered by real-world data. Both OAQPS and EPA Region 8 have advised against the use of the CUECost model, which has been presented by some sources. Instead, the BART Guidelines recommend use of the OAQPS Control Cost Manual:

> The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

As excellent example of a SCR retrofit cost analysis was prepared for the Navajo Generating Station (NGS). The NGS analysis contains the type of vendor estimates and detailed engineering analyses recommended by the BART Guidelines and are necessary to arrive at a reasonable and informed estimate of site-specific costs. In the absence of such a comprehensive analysis, the BART Guidelines recommend use of the EPA Control Cost Manual.

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[5] "Concern over the handling of ammonia was initially raised as a problem with SCR technology applications due to the transportation and storage of a hazardous gas under pressure. However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record. (In 2006, 17 billion pounds of ammonia were produced in the U.S.) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine." WHITE PAPER SELECTIVE CATALYTIC REDUCTION (SCR) CONTROL OF NO_X EMISSIONS FROM FOSSIL FUEL-FIRED ELECTRIC POWER PLANTS PREPARED BY: NOx CONTROL TECHNICAL DIVISION INSTITUTE OF CLEAN AIR COMPANIES, INC. May 2009 Copyright

EPA's belief that the Control Cost Manual should be preferred over CUECost for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to the North Dakota Department of Health:

> The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

Larry Sorrels, an economist at EPA's Office of Air Quality Planning and Standards (OAQPS) wrote the following to Aaron Worstell of EPA Region 8 on September 8, 2010:

> the way that CUECost estimates total capital cost and O&M cost is different from the Control Cost Manual. In particular, the total capital cost estimate from CUECost is the same as the total capital requirement (TCR), an estimate that is part of the levelized cost methodology devised by EPRI. A TCR estimate includes Allowance for Funds Used During Construction (AFUDC), an estimate that is not included in the total capital cost according to the Control Cost Manual method. Also, O&M costs are calculated differently, with fixed and variable components being included in the O&M costs, a distinction at odds with the Cost Manual method.

As recommended by the BART Guidelines, the preferred method for estimating SCR costs involves equipment vendor data (i.e., budget estimates or bids). The EPA Cost Manual is the recommended surrogate for vendor data. Use of the CUECost "black box" model is discouraged by EPA.

Cost Escalation

Mr. Sorrels also commented[6] upon use of Present Value of Revenue Requirements (PVRR) model to calculate the levelized cost of each technology.

> The PVRR model really can't be complementary to the EPA air pollution control cost methodology. The PVRR model is designed to generate nominal, levelized costs that incorporate a return to the equity and debt incurred by the utility that purchases the control equipment. The EPA air pollution control cost methodology generates real (inflation-adjusted), equivalent annual costs over the life of control equipment without consideration of return on equity or debt. Any presentation of PVRR results should state clearly that the pollution control investment is treated just like any other capital investment for a regulated entity - the utility still receives its expected rate of return on its investment and really loses no profit as a result of installation and operation of this NOx control equipment.
>
> Estimating real annual costs means no use of escalation factors, something that is utilized in the PVRR model.

In summation, it is not appropriate to use the CUECost model, nor is it appropriate to escalate costs into the future and compare them against current cost thresholds.

Mr. Sorrels also provided[7] insight on matters pertaining to **inflation** and the **Allowance for Funds During Construction** (AFUDC):

> On cost indexes, I prefer the CEPCI (Chemical Engineering Plant Cost Index) for escalating/deescalating costs for chemical plant and utility processes since this index specifically covers cost items that's pertinent

[6] E-mail dated September 7, 2010 to Don Shepherd of NPS.
[7] 7/21/10 e-mail to Don Shepherd

> to pollution control equipment (materials, construction labor, structural support, engineering & supervision, etc.). The Marshall & Swift cost index is useful for industry-level cost estimation, but is not as accurate at a disaggregated level when compared to the CEPCI. Thus, I recommend use of the CEPCI as a cost index where possible.
>
> I agree with including AFUDC in a capital cost estimate if this is already included in the base case as per a utility commission decision. Otherwise, I do not agree with its inclusion.

For example, CDPHE has included a $26 million cost for "Interest during Construction" for SCR on each of the Craig units that is probably not allowable because Tri-State is not a rate-regulated utility and the AFUDC cost is not "already included in the base case as per a utility commission decision."

"Real-World" SCR Capital Costs

Real-world, utility industry-generated evidence that CDPHE has overestimated its SCR costs can be found in a June 2009 article in "Power" magazine:[8]

"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 generally lower than estimated by CDPHE for Craig.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $106 to $213/kW, converted to 2007 dollars.[9] Costs are escalated through using the CEPCI.

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[8] 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/

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

The second survey of 40 installations at 24 stations reported a cost range of $76 to $242/kW, converted to 2007 dollars.[10]

The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, or 39% of installed SCR systems in the U.S. This study reported a cost range of $118/kW to $261/kW, converted to 2007 dollars.[11]

A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $180/kW to $202/kW, converted to 2007 dollars.[12]

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.[13]

EPA's Region 8 Office has compiled a graphic presentation of SCR capital costs adjusted to 2009 dollars—please see **Appendix B for "SCR References Colorado"**. The EPA data confirm that SCR capital costs typically range from $73 – $243/kW. In comparison, Tri-State's cost estimates for Craig appear to be significantly overestimated.

A graphic illustration of a "real-world" retrofit was presented by Burns & McDonnell at the 2010 Power Plant MegaSymposium and is provided in **Appendix B in the "Boswell retrofit" files**. Despite the limited space and other obstacles, the SCR installation cost $205/kW.[14] It should also be noted that the Boswell #3 retrofit was designed to meet 0.05 lb/mmBtu annual average and a 0.07 lb/mmBtu 30-day rolling average. 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, reported to cost $265/kW,[15] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-

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

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

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

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

[14] 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.

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

constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[16] only cost $251/kW in 2007 dollars.[17]

EPA Control Cost Manual

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

Annual SCR Costs

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

<u>Step 5: Evaluate Visibility Results</u>

We believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas. And, it does not make sense to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. If we look at only the most-impacted Class I area, we ignore that the other Class I areas are all suffering from impairment to visibility "caused" by the BART source. It follows that, if emission from the

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

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

BART source are reduced, the benefits will be spread well beyond only the most impacted Class I area, and this must be accounted for.[18]

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

Step 6: Select BART Control

Cost-Effectiveness Metrics

BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. For example, Oregon DEQ has established a cost/ton threshold of $7,300 based upon the premise that improving visibility in multiple Class I areas warrants a higher cost/ton than where only one Class I area is affected. In their BART proposal for the San Juan Generating Station, New Mexico used a range from $5,946/ton to $7,398/ton, and Wisconsin is using $7,000 - $10,000/ton as its BART threshold.[19]

One of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview. We believe that visibility improvement must be a critical factor in any program designed to improve visibility. Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation[20] of BART analyses across the U.S. reveals that the **average cost per dv proposed by either a state or a BART source is $14 - $18 million**,[21] with a maximum of $51 million per dv proposed by South Dakota at the Big Stone power plant. We note that OR DEQ has chosen $10 million/dv as a cost criterion, which is somewhat below the national average.

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

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

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

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