NPS comments on Best Available Retrofit Technology (BART) Analysis of Control Options for Public Service Company – Comanche Station, Units 1 and 2
November 15, 2010

The Comanche Station is located in Pueblo, CO and consists of three dry-bottom, pulverized coal-fired boilers, two tangentially-fired (Units 1 & 3) and one wall-fired (Unit 2). Units 1 and 2 are considered BART-eligible. Unit 1 commenced operation in 1972 and serves a generator rated at 325 MW. Unit 2 commenced operation in 1975 and serves a generator rated at 335 MW. The boilers burn sub-bituminous coal from the Powder River Basin. In August of 2004, Public Service Company of Colorado (PSCo) proposed to construct and operate a new 600 MW coal-fired boiler (Unit 3) at Comanche Station. As part of that project, PSCo entered into a Settlement Agreement in December 2004 with various citizen groups and voluntarily agreed to install additional control devices and take emission limitations. Low-NO_X Burners (LNB) with over-fire air (OFA) and a lime spray dryer (LSD) were installed in November 2008 on Unit 1 and LNB+OFA+LSD were installed in November 2007 on Unit 2. Operation of the SO_2 controls did not commence until June 3, 2009 for Unit 1 and January 10, 2009 for Unit 2. Unit 3 commenced operation in January 2010.

Remaining Useful Life

In their January 19, 2010 submittal PSCo indicated that the remaining useful life of Comanche Units 1 & 2 are each in excess of 20 years. Thus, this factor does not influence the selection of controls.

New Source Review Compliance

Comanche is still subject to a 2002 EPA enforcement action for major modifications to these boilers. Therefore, Prevention of Significant Deterioration review applies, including the requirement to apply Best Available Control Technology (BACT). PSCo has used reductions in SO_2 and NO_x emissions to avoid PSD review for its new Comanche #3. Now, PSCo is using those same reductions to satisfy BART.

Sulfur Dioxide (SO_2)

NPS: EPA's BART Guidelines for EGUs with existing controls achieving removal efficiencies of greater than 50% recommend that one should evaluate scrubber upgrades. We commend CDPHE for the evaluation of several options, but note that the baseline emission rate calculation by CDPHE applies AP-42 incorrectly. Instead, it would be more appropriate to use actual pre-scrubber emissions, which, for 2000 - 2006, averaged 0.546 and 0.580 lb/mmBtu for Units 1 & 2, respectively. Compared to those uncontrolled emission rates, it appears that the current scrubber configurations would need to achieve 82% and 83% for Units 1 & 2, respectively, to meet the proposed annual BART limit. These levels of control are well within the capabilities of modern LSD systems, and we question whether the Comanche scrubbers are currently being utilized to their fullest capabilities. We would typically expect a modern LSD to remove at least 90% of the uncontrolled emissions, in this case achieving about 0.05 – 0.06 lb/mmBtu.

Although CDPHE concluded that no technically-feasible options were available to reduce SO_2, we note that CDPHE also briefly explored adding a third scrubber module. While PSCo rejected that option due to space constraints, CDPHE should confirm that it concurs with PSCo's opinion, or conduct an analysis of that option.

Filterable Particulate Matter (PM10)

CDPHE: Based on recent BACT determinations, the state has determined that the existing Unit 1 & Unit 2 reverse-air fabric filter baghouses and emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for PM/PM_{10}.

NPS: CDPHE's conclusion is valid only if it is referring to total PM_{10}. Recent BACT decisions have consistently limited filterable PM_{10} to 0.010 – 0.015 lb/mmBtu, and total PM_{10} to the 0.030 lb/mmBtu cited by CDPHE. Furthermore, the Comanche stack test results clearly show that the current baghouses are limiting filterable PM_{10} 0.005 – 0.007 lb/mmBtu. BART should reflect the true capabilities of the Comanche baghouses.

Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

CDPHE: In various submittals with respect to installing additional NO_X controls on Comanche Units 1 & 2, PSCo looked at two options:
• Selective Non-Catalytic Reduction (SNCR)
• Selective Catalytic Reduction (SCR)

As part of this BART evaluation, the Division identified and examined the following additional control options for these units:
• Powerspan Electro-Catalytic Oxidation (ECO)®
• Rich Reagent Injection (RRI)
• Rotating Opposed Fired Air (ROFA), ROFA with SNCR
• Low NO_X Burners (LNB) with Separated Overfire Air (SOFA)
• Reburning

Since low NOX burners with over-fire air (LNB-OFA) were recently installed on Units 1 and 2 (November 2008 for Unit 1 and November 2007 for Unit 2), the Division considers that further upgrades to the LNB-OFA would provide little in the way of additional reductions and therefore upgrades to the existing LNB-OFA were not considered.

NPS: We agree with this suite of options.

Step 2: Eliminate Technically Infeasible Options

CDPHE: SNCR: PSCo has indicated that SNCR is feasible for Unit 1. According to their April 6, 2009 submittal, PSCo conducted testing in the fall of 2008 on Unit 2 using a temporary SNCR system. The testing was done following the installation of LNB-OFA to determine if additional reductions could be achieved. Testing was conducted primarily at full load over a seven-day period using a single-level urea based-SNCR system. The SNCR system is sensitive to temperature and average exhaust temperature in the injection area for Unit 2 was nearly 2,200 ºF, which exceeds the optimal temperature for the technology. During the test periods, NO_X reductions were less than 10%, and in some cases during testing, an actual increase in NO_X

emissions was seen. Therefore, PSCo considers that SNCR is not feasible on Unit 2 and the Division concurs.

NPS: We agree with CDPHE's conclusions in this step.

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

CDPHE: SNCR: In their April 20, 2010 submittal, PSCo indicated that a NO_X emission rate of 0.10 lb/MMBtu was achievable on Unit 1. The Division calculated the control effectiveness based on the difference between the baseline (2009) and expected emission rate. This calculated control effectiveness for Comanche Unit 1 is 29.5%. This control effectiveness estimate is roughly equivalent to EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers.

CDPHE: SCR: In their April 20, 2010 submittal, PSCo indicated that a NO_X emission rate of 0.07 lb/MMBtu was achievable on both Units 1 and 2. Again, the Division calculated the control effectiveness based on the difference between the baseline (2009) and expected emission rate. This calculated control effectiveness for Comanche Unit 1 is 51% and for Comanche Unit 2 is 63%. These control efficiencies are lower than EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NOx emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction. However, the resultant emission rate of 0.07 lb/MMBtu is consistent with the rates cited in the AWMA study. PSCo and the Division recognize and concur that the lower initial emission rates of 0.124 and 0.165 lb/MMBtu for Units 1 & 2 respectively result in reduced SCR control efficiencies.

NPS: The ultimate emission rate achieved by SCR is primarily a function of the design of the SCR reactor (e.g., catalyst volume, area, number of layers, and type). Operational evidence from SCR retrofits on eastern EGUs (see our general comments) clearly indicates that SCR on boilers similar to those at Comanche can achieve 0.05 lb/mmBtu or lower on an annual basis. (The studies cited by CDPHE are vintage 1998 and 2005, and do not reflect current capabilities of SCR.) For example, we found eight dry-bottom boilers and 12 tangentially-fired boilers operating at or below 0.05 lb/mmBtu in 2009.

CDPHE has assumed that 30-day rolling average SCR emissions would be 0.01 lb/mmBtu higher than the corresponding annual average emission rate, and we agree. We looked at monthly data for 28 EGUs with SCR's operating at or below 0.05 lb/mmBtu on an annual average (see our genral comments) and found that, of the 228 months of data, 214 were at or below 0.06 lb/mmBtu. When we looked at wall-fired EGUs, we found that 73 of 77 were at or below 0.06 lb/mmBtu. For tangentially-fired EGUs, we found that 84 of 89 were at or below 0.06 lb/mmBtu. We conclude that SCR at Comanche 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>

Cost of Compliance

CDPHE: SNCR and SCR: In their January 19, 2010 submittal, PSCo provided cost information associated with SNCR for Unit 1 and SCR for both Units 1 & 2. PSCo used EPA's Coal Utility

Environmental Costs (CUECost) workbook model to estimate capital and ongoing operating and maintenance costs. The costs were then levelized at 2016/2017 dollars based on a 20-yr life to determine annual costs. The levelized costs were reported in 2016/2017 dollars on the assumption that SNCR would be installed by 2015 and SCR would be installed by 2016, with an additional year to optimize operation of the new control equipment. PSCo submitted the inputs and outputs from CUECost to the Division in a March 1, 2010 e-mail to the Division. The levelized cost methodology and results were provided in Xcel internal memos dated February, 24, 2010 (submitted to the Division via e-mail on March 1, 2010) and April 16, 2010 (submitted via e-mail to the Division on April 21, 2010). According to PSCo's April 20, 2010 submittal, the cost per ton for SNCR for Unit 1 was estimated to be $ 4,342/ton and the cost per ton for SCR was estimated to be $15,173/ton for Unit 1 and $9,558/ton for Unit 2.

Although the Division does not dispute the levelized annual costs for SNCR and SCR, the baseline emission rates used to determine the cost per ton for the incremental reduction are not appropriate. For Unit 1, PSCo presumed baseline emission rates of 0.12 lb/MMBtu for SNCR and 0.13 lb/MMBtu for SCR and for Unit 2 PSCo presumed a baseline emission rate of 0.18 lb/MMBtu. The Division has set a baseline period of 2009. The baseline emission rates are shown in its Table 1.

NPS: First, we address the appropriateness of the cost methods presented by PSCo and accepted by CDPHE. With respect to use of the CUECost model, according to 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 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.

Both OAQPS and EPA Region 8 have advised against the use of CUECost. 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.

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.

Mr. Sorrels also commented[1] upon PSCo's 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.
>
> This would not be the case for any non-regulated utility or non-utility firm.
>
> The discount rate of 7.88% is a nominal rate, not a real one (consistent with the comment I made above).
>
> Estimating real annual costs means no use of escalation factors, something that is utilized in the PVRR model.
>
> There needs to be more detail on what the capital and O&M estimation methodologies include. There are some allusions to what is contained in these estimates as prepared by GAAR, but no detail. I suppose this detail is in the reports that Xcel will send to the State of Colorado at their request.

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.

CDPHE: SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses. The PSCo-estimated SNCR costs for operating expenses is about 69% for Comanche Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with NOx reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NOx level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.

The Division-calculated cost effectiveness for SNCR on Unit 1 is $3,644 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 1) achieving NOx emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NOx reduced, depending on initial capital costs and capacity factor. It should be noted that PSCo is estimating resultant emission rates much lower than 0.30 lb/MMBtu for this boiler. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NOx reduced. PSCo's estimates are above this range. However, the Division concludes that PSCo's cost estimates for SNCR are reasonable due to the low input NOx emission rate and degree of retrofit difficulty.

NPS: Because, as CDPHE correctly notes, "SNCR is an operating expense-driven technology, its cost varies directly with NOx reduction requirements and reagent usage," it is necessary to estimate SNCR costs for specific cases, not generalizations. And, because of the improper

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

methods used by PSCO to estimate costs, especially water costs, we are submitting SNCR cost estimates (see **Appendix Comanche SNCR**) based upon the EPA Cost manual, as recommended by the BART Guidelines.

SNCR Cost-benefit Analysis

Controlled emissions (lb/mmBtu)	0.087	CDPHE report
Controlled Emissions (tpy)	1,229	calculated
Emissions Reduction (tpy)	537	calculated
Capital Cost	$3,528,121	OAQPS Control Cost Manual
Capital Cost ($/kW)	$11	assumed
Annualized Cost	$719,350	OAQPS Control Cost Manual
Cost-Effectiveness ($/ton)	$1,423	OAQPS Control Cost Manual

CDPHE: SCR: Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NOx emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of NOx reduced, depending on initial capital costs and capacity factor.19,20 In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 15.3% is just slightly higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.21 PSCo's cost estimates are above the NESCAUM study ranges due to the lower control efficiencies explained earlier. The Division concludes that PSCo's cost estimates for SCR are reasonable due to low emission reductions and retrofit difficulties.

NPS: The "recent NESCAUM studies" are vintage 2000 and are not related to utility boilers. And, PSCo used improper methods to estimate costs, especially annual maintenance and catalyst replacement costs (see **Appendix Comanche SCR**), which resulted in overestimation of costs relative to the Cost Manual methods.

Step 5: Evaluate Visibility Results

CDPHE Table 15 indicates that SNCR on Unit #1 can improve visibility at Great Sand Dunes National Park by 0.11 dv and that SCR can improve visibility at Great Sand Dunes National Park by 0.14 dv (Unit #1) and 0.17 dv (Unit #2). This does not include visibility benefits at other Class I areas impacted by Comanche.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein , the state has determined that NOx BART is low NOx burner controls at the following existing NOx emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.20 lb/MMBtu (30-day rolling average)
0.15 lb/MMBtu (combined annual average for units 1 & 2)

Although the other alternatives achieve better emissions reductions, the added expense of these controls were determined to not be reasonable coupled with the low visibility improvement (under 0.2 delta deciview) afforded.

NPS: CDPHE has rejected SNCR and SCR on the basis of inflated cost estimates and underestimates of SCR control-efficiency. We have provided real-world information that demonstrates that SCR can achieve 0.05 lb/mmBtu and better, and that PSCo's cost estimates for SNCR and SCR are inflated. We recommend that BART for Comanche #1 is at least SNCR, and that CDPHE re-evaluate SCR on both units using the EPA Cost Manual methods.