NPS Comments on Best Available Retrofit Technology (BART) Analysis of Control Options for Colorado Springs Utilities – Drake Plant
November 15, 2010

The facility is located in Colorado Springs and consists of three BART-eligible dry-bottom, wall-fired boilers (Units 5, 6, and 7). These boilers fire a variety of coal types, including coal from the southern Powder River Basin, ColoWyo coal (from northwestern Colorado), 20-Mile Foidel Creek coal (northwestern Colorado), and West Elk coal (western Colorado). Due to equipment limitations, these boilers cannot achieve full load on PRB-sourced coal and instead fire a blend of the above-listed coals. CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis.

CDPHE used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results.

Sulfur Dioxide (SO2)

Step 1: Identify All Available Technologies

CDPHE: CSU identified one control option for Units 6 and 7:
- Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)

CSU identified two control options for Unit 5:
- Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)
- Dry sorbent injection – Trona (DSI)

The Division also identified and examined Lime/limestone-based wet FGD as an additional control option for these units

CSU-Drake is currently testing a new, innovative NeuStream-S wet scrubber system that appears to be as effective, if not more effective, at controlling SO_2 emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. Although the technology being tested by CSU does not technically meet the definition of "available" as set forth in the BART rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber. This process will be required to meet the emission limits established for the LSD technology established in this BART determination. Regardless of the technology utilized, Drake has to meet the LSD-based BART limits within five years of EPA approval of the BART SIP. CSU will test the NeuStream system until December 2011, and at that time, determine the control technology that will be used to comply with the specified SO_2 BART limits for Units 6 and 7.

NPS: CDPHE has selected a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options

CDPHE: For Unit 5, CSU determined dry FGD controls are technically feasible although available physical space was severely constrained and some demolition and site reconfiguration would be required; the Division conducted a site visit and determined that dry FGD controls were not appropriate considering the space constraints.

NPS: We defer to CDPHE.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CDPHE: CSU provided the Division annual average control estimates. In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Units 5, 6, and 7 to determine control efficiencies and annual reductions.

NPS: We agree.

CDPHE: Dry FGD (LSD): "Controlling SO_2 Emissions: A Review of Technologies" indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Drake Power Plant, typically <0.5%, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Additionally, achievement of a 90% removal rate on a long-term basis would require levels of equipment redundancy that may not be feasible to locate at a congested site such as the Drake Power Plant. For dry FGD, CSU estimated a removal rate of 83.3% based on a worst-case coal sulfur concentration of 0.9 lb/MMBtu, baseline years 2004 and 2005, and a resulting emission rate at the BART presumptive limits of 0.15 lb/MMBtu. The Division adjusted this removal rate using the baseline SO_2 emissions for each unit and using a realistic removal rate of 76 – 90% that meets or exceeds BART presumptive limits for Units 6 and 7, and exceeds the limits for Unit 5. This range allows the Division to determine the most reasonable BART limit for this control option, if applicable.

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

Section V. Specific Operating Conditions (continued)

A. Emission Unit #S2.001 - Pulverized Coal Fired Boiler (continued)

2. NAC 445B.3405

a. Emission Limits (continued)

(7) Article 8.2.1.2 *Federally Enforceable SIP* - The discharge of sulfur to the atmosphere will not exceed **1,218.0** pounds per hour.

(8) NAC 445B.305 *BACT Emission Limit* – The discharge of SO_2 to the atmosphere will not exceed:

(i) While combusting coal with a Sulfur content equal to or greater than 0.45 percent (30-day rolling period), based on daily ASTM sampling:

(a) **0.09** pound per million Btu, based on a 24-hour rolling average period.

(b) 95% minimum SO_2 removal efficiency will be maintained across the system, based on a 30-day rolling period.

(ii) While combusting coal with a Sulfur content less than 0.45 percent (30-day rolling period), based on daily ASTM sampling:

(a) 0.065 pound per million Btu, based on a 24-hour rolling average period.

(b) 91% minimum SO_2 removal efficiency will be maintained across the system, based on a 30-day rolling period.

NPS: The Newmont Nevada permit indicates that a modern LSD can achieve greater than the 90% maximum assumed by CDPHE, even on low-sulfur coals.

CDPHE: DSI: Based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved to be 60% SO2 removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

NPS: We agree.

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

CDPHE for DSI: CSU only submitted DSI cost information for Unit 5. The Division scaled this cost information for Units 6 and 7. CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants, which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

NPS: CSU has presented no evidence that DSI would render the ash unsalable. Our discussions with DSI vendors indicates that this claim may be false.

CDPHE has based its $6 million Total Capital Cost estimates for DSI at on information provided by CSU on Drake #5 on 5/10/10. CDPHE has provided information allowing us to determine how it estimated annual operating costs for DSI on Drake #5. When we revised CDPHE's Annual Trona Costs ($238,735) and corrected the other Direct and Indirect Annual Costs to eliminate mercury controls, we arrived at a Total Annual Cost of $1.4 million for DSI on Drake #5 instead of the $1.7 million used by CDPHE in its BART determination. The resulting control cost drops to $1,844/ton instead of the $2,293/ton evaluated by CDPHE.

CDPHE for LSD: The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable.

NPS: Although it is not clear how CDPHE scaled the costs for differing levels of control, taken at face value, the CDPHE 90% control estimates of $2,973/ton for Unit #6 and $2,481/ton for Unit #7 are not substantially higher than the $2,808/ton and $2,483/ton accepted by CDPHE as BART at 85% control.

Step 5: Evaluate Visibility Results

NPS: The addition of DSI to Unit #5 would improve visibility by 0.12 dv at Rocky Mountain National Park. Increasing the SO_2 control efficiency of the LSDs proposed for Units #6 and #7 would improve visibility by 0.02 dv each.

Step 6: Select BART Control

CDPHE: Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART for Unit 5 is no control at the following existing SO_2 emission rate as previously adopted in Regulation No. 1:
Drake Unit 5: 1.2 lb/MMBtu (3-hour average)

NPS: According to CDPHE, DSI on Drake #5 results in a 0.12 dv improvement at Rocky Mountain National Park, the cost/ton is $2,293, and the cost/dv is $14.7 million. Using the revised cost estimates provided by CDPHE along with additional revisions we discuss above, we arrive at $1,844/ton and $11.7 million/dv. Although CDPHE rejected DSI on Drake #5, its estimated cost-effectiveness of $11.7 million/dv is lower than the $14 - $18 million/dv average cost-per-deciview of improvement proposed by states and sources. On that basis, DSI should be selected as BART.

CDPHE: Based upon its consideration of the five factors summarized herein, the state has determined that SO2 BART for Unit 6 and Unit 7 is semi-dry FGD (LSD) controls at the following SO2 emission rates:
Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)
Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

The LSD controls for Units 6 and 7 provide 85% SO_2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.
• Unit 6: $2,808 per ton SO_2 removed; 0.24 deciview of improvement
• Unit 7: $2,345 per ton SO_2 removed; 0.39 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.13 lb/MMBtu, 30-day rolling average, may also be employed.

NPS: The 85% SO_2 BART option proposed by CDPHE would result in cost-effectiveness values of $27.5 and $22.7 million/dv for Units #6 & #7, respectively. According to CDPHE, increasing the SO_2 control efficiency of the LSDs proposed for Units #6 and #7 would improve visibility by 0.02 dv each at Rocky Mountain National Park. While we commend CDPHE for its efforts to improve visibility at Rocky Mountain National Park, we believe that the proposed LSD scrubbers are capable of even greater emission reductions, thus resulting in 8% and 5% greater visibility improvements at Units #6 & #7, respectively, with a relatively small (6%) increase in annual cost cost/dv. In addition, if the NeuStream system proves to be more effective than assumed for the LSD option, then an appropriately lower emission limit should be set.

Filterable Particulate Matter (PM10)

CDPHE: Drake Units 5, 6, and 7 are each equipped with reverse-air fabric filter baghouses to control PM/PM_{10} emissions.

The Division determines that the existing Unit 5, 6, and 7 reverse-air fabric filter baghouses and the existing regulatory emissions limits of 0.03 lb/MMBtu (PM/PM10) represent the most stringent control options.

The Division used a variety of information, including similar Colorado and western facility PM/PM_{10} emission limits, the RBLC database, stack test results, and consideration of existing controls to make PM_{10} determinations. The Division notes that the most recent stack test results for Drake are lower than the 0.03 lb/MMBtu. However, one singular stack test is supporting information and not comprehensive when determining an emission limit. The Drake boilers are required to use the result of the stack test to determine annual emissions as well as maintain and operate the baghouses in accordance with good engineering practices. Additionally, the continuous opacity monitors (COMs) indicate baghouse performance. This combination of information led the Division to the conclusion that 0.03 lb/MMBtu and the existing reverse-air fabric filter baghouses represent the most stringent control option for BART.

NPS: Considering that the stack test results for Drake ranged from 0.0111 - 0.0186 lb/mmBtu, it is unclear how CDPHE used that data and the Continuous Opacity Monitor data to arrive at its conclusion.

Nitrogen Oxide (NOx)

Step 1: Identify All Available Technologies

CDPHE: CSU identified four NOx control options:

- Overfire air (OFA)
- Ultra-low NOx burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low NOx burners and SCR (ULNBs + SCR)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Selective Non-Catalytic Reduction (SNCR)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because it would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit.

NPS: CDPHE improperly excluded ROFA with Rotamix® that, according to Minnesota Power, can achieve up to 68% NO_X control on its coal-fired 75 MW Taconite Harbor Unit #3. CDPHE should also evaluate compatible combinations of control options (e.g., ULNB+OFA)

Step 2: Eliminate Technically Infeasible Options

CDPHE: ***ECO®:*** This technology has not been demonstrated on a full-size pulverized coal-fired boiler and thus, is considered technically infeasible.
RRI: Rich reagent injection was developed for cyclone boilers and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 5, 6, and 7.
Coal Reburn + SNCR: has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

NPS: We agree.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CDPHE: OFA: The Division concurs with CSU's additional 20% NOx control estimate.

CDPHE: ULNBs: The ULNBs are estimated to control approximately 75% of uncontrolled NOx emissions, which is consistent with a U.S. Department of Energy Study which estimated NOx emissions reductions between 75 – 85%. Therefore, the Division concurs with CSU NOx reduction estimates for ULNBs.

CDPHE: SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study to conservatively approximate that the Drake boilers can achieve 30% control when SNCR is applied.

NPS: We assume that the "similar Colorado facility" is CENC which, as we note in our comments on that BART analysis, suffers from a similar problem with "circular logic" and a lack of information to support such a low efficiency estimate. As for "EPA's SNCR Air Pollution Control Fact Sheet," that 2002 document is out-of-date but still estimates that SNCR can achieve 30% - 50% NO_X control efficiency. We suggest that a more appropriate estimate can be found where the North Dakota Department of Health is proposing that the coal-fired 188 MW Stanton Generating Station install SNCR with an estimated 45% NO_X control efficiency.

SCR: CSU approximates that SCR can achieve an approximate 80% NOx reduction using 2004 – 2005 baseline emissions (or 0.07 lb/MMBtu), determined by URS WD. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions, but kept the resultant 0.07 lb/MMBtu constant. This control efficiency is consistent with EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NOx emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.

NPS: As we demonstrate in much greater detail in our general comments,[1] there is overwhelming evidence to support a lower (0.06 lb/mmBtu) "target" for SCR. The "recent" studies cited by CDPHE are vintage 1998 and 2005, and do not reflect current capabilities of SCR.

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

CDPHE: OFA: Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake boilers in 2004. The cost estimates were generated using EPRI's IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "NOx Controls for Existing Utility Boilers," OFA alone ranges from $410 - $1,100 per ton NOx reduced annually for units estimating 15 – 30% NOx control, which is within the range of Drake's estimated OFA NOx reductions (20%). Therefore, the Division concurs with the OFA cost estimates.

ULNBs: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 19, Table 21, and Table 23. The Division considers CSU's estimated costs more than

[1] We are providing information that supports use of 0.05 lb/mmBtu as an annual NO_X emission rate.

reasonable, with ULNBs under $1,000/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.

SNCR: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the Drake boilers. The Division used information from a similar facility[2] submittal to determine approximate SNCR costs for the Drake boilers since CSU did not have SNCR information. The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Drake boilers in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 5, 6, and 7 ranges from $2,700 to $4,400 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers 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. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NOx reduced. Although the resulting cost estimates for the Drake boilers are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

NPS: CDPHE has provided no evidence to support its speculation regarding any special problems associated with installing SNCR at Drake. And, once again, CDPHE is relying upon flawed analyses at a "similar facility" (CENC). Instead, as recommended by CDPHE and by the BART Guidelines, we are providing SNCR cost estimates based upon methods described by EPA's Control Cost Manual (Cost Manual). Our analyses, summarized below **(and provided in Appendix Drake SNCR)** show that, even at the low 30% control efficiency estimate used by CDPHE, SNCR can reduce NO_X emissions at $700 - $1000/ton, which is much less than the $2,800 - $4,300/ton estimated by CDPHE.

SNCR Cost-benefit Analysis

Unit	5	6	7	
Controlled emissions (lb/mmBtu)	0.26	0.29	0.28	CDPHE report
Controlled Emissions (tpy)	568	1,030	1,604	CDPHE report
Emissions Reduction (tpy)	274	471	691	CDPHE report
Capital Cost	$ 1,556,844	$ 1,920,889	$ 2,328,330	OAQPS Control Cost Manual
Capital Cost ($/kW)	$ 31	$ 23	$ 16	calculated
O&M Cost	$ 117,885	$ 176,126	$ 243,640	OAQPS Control Cost Manual
Annualized Cost	$ 264,840	$ 357,445	$ 463,418	OAQPS Control Cost Manual
Cost-Effectiveness ($/ton)	$ 989	$ 792	$ 715	OAQPS Control Cost Manual

CDPHE: SCR: CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan

[2] This (CENC) submittal evaluated SNCR for boilers sized at 35 and 65 MW. The Division used the SNCR annualized cost, which was then scaled linearly for the Drake boilers to evaluate cost effectiveness. For example, the SNCR annualized cost multiplied by a ratio of 51 MW/35 MW, resulted in the annualized cost for Boiler 5 (sized at 51 MW). For Boilers 6 and 7, the Division scaled costs based on the larger 65 MW boiler at the other facility.

does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving NOx emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing $2,600 - $7,400 per ton of NOx reduced, depending on initial capital costs and capacity factor. The SCR system estimates for the CSU Drake boilers range from approximately $5,000 - $7,100, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

NPS: We are providing information in our general comments from electric utility industry studies that shows that the Total Capital Investment (TCI) costs for adding SCR to utility boilers larger than 100 MW are less than $300/kW, with most costing around $200/kW. Our review of the SCR cost estimates provided by CDPHE leads us believe that TCI costs of $558, $448, and $325/kW for units #5, #6, sand #7, respectively, are overestimated. Specifically, TCI costs are overestimated when compared to the Cost Manual's 1.41:1 ratio of TCI to Total Direct Cost. However, when we apply the Cost Manual method to estimate Direct and Indirect Annual costs, we see much greater evidence that these critical annual costs have been overestimated. Therefore, we are providing SCR cost estimates summarized below **(and provided in Appendix Drake SCR)** based upon methods described by the Cost Manual.

SCR Cost-benefit Analysis

Unit	5	6	7	
Controlled emissions (lb/mmBtu)	0.05	0.05	0.05	assumed
Controlled Emissions (tpy)	107	170	269	calculated
Emissions Reduction (tpy)	716	1,268	1,885	Cost Manual
Capital Cost	$ 24,874,756	$ 31,489,153	$ 37,431,733	Cost Manual
Capital Cost ($/kW)	$ 452	$ 370	$ 264	calculated
Annualized Cost	$ 2,955,084	$ 3,835,776	$ 4,693,930	Cost Manual
Cost-Effectiveness ($/ton)	$ 4,130	$ 3,025	$ 2,490	Cost Manual

Application of the Cost Manual methods shows that SCR can reduce NO_X emissions at $2,500 - $4,200/ton, which is much less than the $5,000 - $7,300/ton estimated by CDPHE.

Step 5: Evaluate Visibility Results

CDPHE Table 25 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Step 6: Select BART Control

CDPHE: Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART for Units 5 and 6 is over-fire air control at the following existing NOx emission rate:
Drake Unit 5: 0.39 lb/MMBtu (30-day rolling hour average)
0.35 lb/MMBtu (12-month rolling average)

Drake Unit 6: 0.39 lb/MMBtu (30-day rolling hour average)
0.35 lb/MMBtu (12-month rolling average)

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

NPS: The CDPHE BART proposal is internally inconsistent. Considering that the $/ton and $/dv estimates for ULNB on Drake #5 are lower than for the proposed OFA at Drake #5, why was the less-effective OFA proposed as BART for Drake #5? Considering that the $/ton and $/dv for ULNB on Drake #6 are lower than for the proposed ULNB at Drake #7, why was the less-effective OFA proposed as BART for Drake #6?

We have shown that SNCR can provide greater NO_X reductions at $800 - $1000/ton. When the benefit of improved visibility at Rocky Mountain National Park is considered, the cost-effectiveness of adding SNCR becomes $3.3 million/dv for Drake #5 and $1.9 million/dv for Drake #6, well below the $14 - $18 million/dv average cost-per-deciview of improvement proposed by states and sources. On that basis, SNCR could be selected as BART.

We have also shown that SCR can provide greater NO_X reductions at $3,000/ton if added to Drake #6. Considering visibility benefits, the cost-effectiveness of adding SCR becomes $14.2 million/dv for Drake #6, consistent with the $14 - $18 million/dv average cost-per-deciview of improvement proposed by states and sources. On that basis, SCR should be selected as BART for Drake #6.

CDPHE: Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART for Unit 7 is ultra low NOx burner controls at the following NOx emission rates:
Drake Unit 7: 0.33 lb/MMBtu (30-day rolling average)

The state has determined that for Unit 7, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan.
• Unit 7: $662 per ton NOx removed; 0.24 deciview of improvement

The extremely low dollars per ton control costs, coupled with notable visibility improvements, leads the state to selecting ULNBs as BART for Unit 7. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the visibility improvement does not meet the criteria guidance described above (*e.g.* less than 0.50 Δdv)

NPS: We have shown that SNCR can provide greater NO_X reductions at $700/ton. When the benefit of improved visibility at Rocky Mountain National Park is considered, the cost-effectiveness of adding SNCR becomes $1.9 million/dv, well below the $14 - $18 million/dv average cost-per-deciview of improvement proposed by states and sources. On that basis, SNCR could be selected as BART for Drake #7.

We have also shown that SCR can provide greater NO_X reductions at $2,500/ton. Considering visibility benefits, the cost-effectiveness of adding SCR becomes $12.7 million/dv, below the

$14 - $18 million/dv average cost-per-deciview of improvement proposed by states and sources. On that basis, SCR should be selected as BART for Drake #7.