NPS Summary Comments on Colorado Reasonable Progress Sources and Craig Generating Station
December 15, 2010

Colorado Department of Public Health and Environment (CDPHE) has prepared Best Available Retrofit Technology (BART) and Reasonable Progress (RP) analyses that are among the most thorough, well-researched, and clearly presented of any we have seen around the nation. We have commented that some of the control efficiency assumptions are too low and some of the cost assumptions are too high, but we are complimentary of CDPHE's overall process. We hope that our national perspective allows us to share some additional insights with CDPHE that will lead to even better results.

Tri-State—Craig Station

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is a coal-fired power plant with a total net electric generating capacity of 1,264 MW, consisting of three units. Of 1,228 plants, EPA Clean Air Markets (CAM) data for 2008 rank the Craig facility #304 for Sulfur Dioxide (SO_2) and #43 for nitrogen oxides (NO_X). In 2009, Craig Units 1, 2, and 3 ranked in that order as the largest NO_X emitters in Colorado. The cumulative impacts of the Craig Station across the eleven Class I areas modeled is greater than 10 dv, which ranks this facility among the highest[1] of any we have evaluated under the BART program.

On December 9, 2010, CDPHE provided Tri-State's "Exhibit 20 - J.E. Chichanowicz Report Current Capital Cost and Cost Effectiveness - January 20." A recurring theme appears on the first page of that exhibit and is repeated throughout. According to Mr. Chichanowicz:

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

While this is probably true for eastern utilities where trading programs allow utilities to pick and choose which units they will control to reach a system-wide reduction target, it is not true in the West where no such flexibility exists under the BART/RP program. In the west, it is more likely that the population of BART Electric Generating Units (EGUs) is representative of typical installations with a typical range of retrofit costs, not the more-difficult "left-overs" discussed by Mr. Chichanowicz.

Finally, while retrofitting SCR on each of the Craig units poses some unusual problems, they are no different in general scope than similar situations described below:

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[1] The highest are Cholla Generating Station, Coronado Generating Station, Four Corners Power Plant, Navajo Generating Station, Centralia, PGE Boardman, and San Juan Generating Station.

Minnesota Power Boswell Station Unit #3: "Because of the large footprint of the new equipment, and because the existing particulate scrubber could not be demolished, some of the Blackwater Lake needed to be reclaimed in order to make space for the new equipment…Some of the Blackwater Lake was filled in, and then the sheet piling was installed. Backfilling behind the sheet piling was then done, and the new air pollution control equipment was constructed on the reclaimed land…Due to site constraints discussed previously, the SCR reactor was located above the existing particulate scrubber building instead of at-grade. The existing particulate scrubber building was not designed to handle the additional weight of the SCR reactor. Therefore, the SCR reactor is supported by a 160-foot long structural steel truss that spans the existing particulate scrubber building." Despite the limited space and other obstacles, the SCR installation cost $205/kW.[2]

Arizona Public Service: "(Cholla) Unit 3 fabric filter was not constructed as a new structure. In an interest to conserve space onsite the new Unit 3 fabric filter was constructed through converting one of the two abandoned Unit 4 Electro Static Precipitators (ESPs)."[3] The need to deal with an existing unused ESP is not an insurmountable obstacle.

Salt River Project Navajo Generating Station:[4] Despite the limited space and other obstacles, the SCR installation is projected to cost $207 - $280/kW.[5]

As noted in our "Supplemental Comments," Tri-State has provided no real-world data to support its $500 - $600/kW SCR cost estimates. Even when we assumed $400/kW (higher than any SCR cost in the exhibits presented by Tri-State or our cost database), the cost/ton is less than $5,000. The largest NO_X source in Colorado and the source having the largest impact upon visibility on multiple Class I areas deserves to be controlled at least as well as the Hayden and Pawnee power plants, which will be retrofitted with SCR.

Platte River Power—Rawhide Energy Station Unit #101

The Platte River Power Authority (PRPA) Rawhide Energy Station consists of one tangentially-fired electric generating unit (EGU #101), with a rated electric generating capacity of 305 MW (gross), and was placed into service in 1984. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and a lime spray dry absorber controlling SO_2. The boiler is equipped with low NOx concentric firing system (LNCFS) burners with separated overfire air (SOFA) configuration for minimization of NOx emissions, installed in 2005. Of 1,228 plants, EPA Clean Air Markets (CAM) data for 2008 rank Rawhide #101 at #931 for SO_2 and #526 for NO_X. In 2009, Rawhide #101 ranked as the 11th largest NO_X emitter and the 19th largest SO_2 emitter in Colorado. CDPHE modeling data show

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[2] 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.

[3] Please see slides #38 - #48 of the Full Scale Demonstration of a Plant Wide Multi- Pollutant Control Project 18 Months in Operation 2010 Power plant MegaSymposium Paper #: Control Number 79 Joseph W. Mashek Burns and McDonnell provided to CDPHE on 12/14/10.

[4] "***Navajo Generating Station Preliminary Capital Cost Estimate***" prepared by Sargent & Lundy and presented by Salt River Project to the Environmental Protection Agency – July 20, 2010, copy provided to CDPHE 12/02/10.

[5] 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.

that Rawhide #101 emissions have a maximum impact at Rocky Mountain National Park of 1.2 dv.

We agree with CDPHE's SO_2 RP determination, and commend them for a thorough analysis. While we agree that the baghouse represents the "most stringent control option" for PM, the proposed limit is not. For example, Arizona Department of Environmental Quality has proposed a BART limit of 0.015 lb/mmBtu for Cholla Units 3 and 4. CDPHE should investigate potential upgrades to the Rawhide baghouse to reduce emissions. Although we do not agree with the methods used in the NO_X analysis to estimate SCR costs and benefits, we agree that the proposed enhanced combustion controls are a reasonable approach to improving visibility at Rocky Mountain National Park for this phase of the Regional Haze program.

Colorado Springs Utilities—Ray D. Nixon Power Plant

The Nixon facility includes one boiler firing low sulfur western coal as the primary fuel. Of 1,228 plants, EPA Clean Air Markets data for 2008 rank the Nixon facility at #497 for SO_2 and #793 for NO_X. In 2009, Nixon ranked as the 12th largest NO_X emitter and the 3rd largest SO_2 emitter in Colorado. CDPHE modeling data show that Nixon emissions have a maximum impact at Rocky Mountain National Park of 0.9 dv.

Sulfur Dioxide (SO_2)

CDPHE has determined that:
SO_2 RP is semi-dry FGD (lime spray dryer, LSD) control at the following SO_2 emission rate:
Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period. The LSD control for Unit 1 provides 78% SO2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton SO2 removed; 0.46 deciview of improvement

NPS: Although "most SDA (spray dryer absorber = LSD) equipment is designed for 93-95% SO_2 removal,"[6] CDPHE assumed that it could achieve only 78% - 82.3% removal. That "stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado" is more indicative of the need for CDPHE to consider tighter limits than a limitation of the technology. Considering that Colorado is not achieving the Uniform Rate of Progress needed at Rocky Mountain National Park, CDPHE should accept all reasonable measure to improve visibility. Even by CDPHE's calculations, LSD at 82.3% removal is reasonable with respect to $/ton and achieves additional visibility improvement. A limit of 0.08 lb/mmBtu would therefore be more "reasonable."

[6] **CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSIONS CONTROL TECHNOLOGIES** Prepared by J. Edward Cichanowicz Prepared for Utility Air Regulatory Group January 2010.

Filterable Particulate Matter (PM) & Particulate Matter (PM10)

CDPHE: Nixon Unit 1 is equipped with a reverse-air fabric filter baghouse to control PM/PM_{10} emissions. The state determines that the existing Unit 1 reverse-air fabric filter baghouse and a regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) represent the most stringent control options.

NPS: While we agree that the baghouse represents the "most stringent control option" for PM, the proposed limit is an order of magnitude higher than test results (0.0021 lb/mmBtu) cited by CDPHE. Instead, CDPHE should set limits that reflect proper operation and maintenance of the current emission control equipment.

Nitrogen Oxides (NO_X)

Although we do not agree with the methods used in the NO_X analysis to estimate SCR costs and benefits, we agree that the proposed over-fire combustion controls are a reasonable approach to improving visibility at Rocky Mountain National Park.

Tri-State Generation & Transmission Association, Inc.—Nucla Station

The Tri-State Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. The boiler is equipped with a fabric filter (baghouse) system for controlling PM emissions, and limestone injection into the fluidized bed for the removal of SO_2. The boiler is designed for the reduction of NOx formation and a small Selective Non-Catalytic Reduction (SNCR) system using anhydrous ammonia injection is used for NOx trim to ensure compliance with annual NOx limits. Of 1,228 plants, EPA Clean Air Markets data for 2008 rank Nucla at #935 for SO_2 and #303 for NO_X. In 2009, Nucla ranked as the 15^{th} largest NO_X emitter and the 15^{th} largest SO_2 emitter in Colorado.

Sulfur Dioxide (SO_2)

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 cost-effective RP is limestone injection improvements at the following SO_2 emission rate:

Nucla Unit 4: 0.18 lb/MMBtu (30-day rolling average)

Limestone injection improvements maximize existing SO_2 control for a modest cost per ton, provides over 500 tpy SO_2 reductions, and for this facility is determined to be reasonable for this planning period.

NPS: Although we commend CDPHE for the proposed reduction in SO_2 emissions, it has improperly eliminated a potentially more-effective technology from consideration. According to CDPHE:

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

- ***Hydrated Ash Reinjection (HAR):*** EPA references vendor information showing that hydrated ash reinjection could reduce the post-combustion SO_2 emissions by about 80%. This results in about 95% reduction from uncontrolled SO_2 emissions.

- ***Hydrated Ash Reinjection + Limestone Injection Improvements:*** It may be possible to combine HAR (80% reduction) with improvements to the limestone injection system (85% reduction). This results in a potential 87.9% decrease from current SO_2 emissions or 96.9% reduction from uncontrolled SO_2 emissions.

Step 4: Evaluate Factors and Present Determination

- ***HAR/HAR+Limestone Injection Improvements:*** Study-level information for potential HAR systems at Nucla or any other EGU in the western part of the country were not available for use in evaluating costs. Since the option to install an SDA system alone (even without improvement of the limestone reinjection system) provides a better estimated control efficiency than an HAR system plus limestone injection upgrades, the HAR system will not be considered further in this analysis.

While it may be true that the SDA system alone provides better estimated control efficiency than an HAR system, unless CDPHE chooses the more-efficient SDA system, it must evaluate the less-effective options. Instead, CDPHE chose "limestone injection improvements" which would achieve less than half the reductions CDPHE estimated for the HAR options. Please reconsider the HAR options.

Filterable Particulate Matter (PM) & Particulate Matter (PM10)
Nixon Unit 1 is equipped with a reverse-air fabric filter baghouse to control PM/PM_{10} emissions. The State has determined that the existing Unit 4 fabric filter baghouse and regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option.

While we agree that the baghouse represents the "most stringent control option" for PM, the proposed limit is double the test results (0.014 lb/mmBtu) cited by CDPHE. Instead, CDPHE should set limits that reflect proper operation and maintenance of the current emission control equipment.

Nitrogen Oxides (NOx)
CDPHE: Based upon its consideration of the five factors summarized herein, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

As an element of this Reasonable Progress determination, Tri-State shall conduct appropriate testing, in consultation with the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla, a circulating fluidized bed boiler, to determine potential boiler-specific NOx control efficiencies, and also to conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts for different NOx control scenarios. The Commission requires that Tri-State complete these efforts, including submitting a report to the Division discussing the results and proposing any preferred control strategy, by July 1, 2012.

NPS: We concur.

Colorado Energy Nations, Golden, Colorado

CDPHE has determined that no control for SO_2 and NO_X represents reasonable progress for Boiler #3 that emits 245 tpy of SO2, 38 tpy PM_{10}, and 169 tpy of NO_X. One of the options rejected by CDPHE was:

> *Fuel Switching – Natural Gas:* The Division used EPA's Cost Control Manual to estimate annual operating costs, of approximately $25,000 per ton of SO_2 removed annually for Boiler 3 at the CENC facility. However, it should be noted that natural gas prices vary significantly; the Division used 2008 commercial natural gas prices reported by the U.S. Energy Information Administration to determine natural gas costs. Therefore, the Division concurs that the natural gas estimates submitted by CENC on May 7, 2010 to be reasonable.

CDPHE also estimates that switching Boiler #3 to natural gas would reduce combined SO_2 and NO_X emissions by 304 tpy at a cost of $1,428,911/yr and improve visibility at Rocky Mountain National Park by 0.18 dv. Considering that switching to natural gas would also virtually eliminate the PM_{10} emissions, taken at face value, CDPHE's estimates lead to the conclusion that switching to natural gas would reduce atmospheric loading of SO_2, NO_X and PM_{10} by 342 tpy at $4,200/ton and $8 million/dv.

Although these results indicate that CDPHE's estimates favor switching to natural gas for reasonable progress, we are concerned that CDPHE's analysis has used 2008 as the basis for its $9.26/mcf natural gas price. Coincidentally, 2008 represents the peak year for natural gas prices. The same Energy Information Administration (EIA) website referenced by CDPHE shows that 2009 natural gas prices were less than half of the 2008 prices. Furthermore, the EIA website used by CDPHE forecasts that natural gas prices will not reach 2008 levels again until 2023. Based upon the 2010 $5.17/mcf price of natural gas delivered to industrial facilities, the cost-effectiveness of switching CENC Boiler #3 to natural gas would drop to $2,300/ton and $4.5 million/dv. We believe that the multiple benefits of switching from coal to natural gas lead to a conclusion that this strategy represents Reasonable Progress.

Holcim Portland Plant, Florence, Colorado

We concur with the CDPHE determination.