# Best Available Retrofit Technology (BART) Analysis of Control Options For

# Tri-State Generation & Transmission Association, Inc. - Craig Station Units 1 & 2

# I. Source Description

Owner/Operator: Tri-State Generation & Transmission Association, Inc.

Source Type: Electric Utility Steam Generating Unit

SCC (EGU): 10100222

Boiler Type: Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired

(Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

<u>Units 1 & 2</u>: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO<sub>2</sub>) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO<sub>x</sub>) dual register burners with overfire air for minimization of NO<sub>x</sub> emissions. The FGD and ultra low NO<sub>x</sub> burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

<u>Unit 3</u>: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO<sub>2</sub> and low-NO<sub>x</sub> burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO<sub>x</sub> limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

**Error! Reference source not found.** below lists the units at Tri-State Craig Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

**Table 1: Craig Boilers Technical Information** 

	Unit 1	Unit 2
Placed in Service	1980	1979
Gross Boiler	4,417	4,417

Rating, MMBtu/Hr for coal		
Electrical Power Rating, Net Megawatts	428	428
Description	Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.	Babcock & Wilcox Pulverized Coal Opposed- Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.
Air Pollution Control Equipment	PM/PM <sub>10</sub> – Pulse Jet Fabric Filter Baghouse NO <sub>x</sub> – Ultra-low NO <sub>x</sub> Burners with Over-Fire Air SO <sub>2</sub> – Wet Limestone FGD	PM/PM <sub>10</sub> – Pulse Jet Fabric Filter Baghouse NO <sub>x</sub> – Ultra-low NO <sub>x</sub> Burners with Over-Fire Air SO <sub>2</sub> – Wet Limestone FGD
	All updated control equipment commenced full operations in 2004.	All updated control equipment commenced full operations in 2004.
Emissions Reduction (%)*	NO <sub>x</sub> - 23.8% /53.9% SO <sub>2</sub> - 77.6%	NO <sub>x</sub> - 29.5%/54.7% SO <sub>2</sub> - 79.5%
	PM – 99.6% PM <sub>10</sub> – 99.4%	PM – 99.9% PM <sub>10</sub> – 99.5%

<sup>\*</sup>Emissions Reduction estimated by comparing pre-control 2001 - 2002 CAMD data to controlled 2006 - 2008 data. The first  $NO_x$  number compares the additional reduction achieved by the ultra-low  $NO_x$  burners vs. the original low- $NO_x$  burners and the second  $NO_x$  number compares uncontrolled AP-42 factor to actual average emission factor (2006 - 2008). For PM/PM<sub>10</sub>., uncontrolled AP-42 factor were compared to actual average emission factors (2006 - 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>10</sub>), and commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as "TriState BART Submittals".

## II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline" Emissions", to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division 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. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions

		Unit 1	Unit 2					
Pollutant	Annual Emissions*	Average Emissions**	Annual Emissions*	Average Emissions**				
	(tpy)	(lb/MMBtu)	(tpy)	(lb/MMBtu)				
$NO_x$	5,190	0.278	5,372	0.271				
$SO_2$	970	0.052	982	0.050				
$PM_{10}$	80	0.006***	40	0.005***				

<sup>\*</sup>Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

## III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking subbituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. The Trapper contract expires in 2014. Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of NO<sub>x</sub>-forming characteristics, Craig 1&2 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO<sub>x</sub> formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

**Table 3: Craig Station Coal Specifications (2008)** 

Coal Mine/Region	Colowyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H <sub>2</sub> O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57
Heating Value (HHV Btu/lb)	10,392	9,800	11,084

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for Craig BART-eligible sources<sup>1</sup>

	Pollutant (lb/ton)*						
Emission Unit	$NO_x$ $SO_2$ $PM$ $PM$			$PM_{10}$			
			(filterable)	(filterable)			
Unit 1	12	16.9	73.9	17.0			

<sup>&</sup>lt;sup>1</sup> EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

<sup>\*\*</sup>The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for  $NO_x$  and  $SO_2$  emissions.

<sup>\*\*\*</sup>The PM<sub>10</sub> emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

Unit 2	12	16.1	71.1	16.4

<sup>\*</sup>SO<sub>2</sub> and PM/PM<sub>10</sub> factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

## IV. BART Evaluation of Units 1 and 2

# A. Sulfur Dioxide (SO<sub>2</sub>)

# Step 1: Identify All Available Technologies

Wet FGD Upgrades – As discussed in EPA's BART Guidelines<sup>2</sup>, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the wet FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:

- -Elimination of bypass reheat
- -Installation of liquid distribution rings
- -Installation of perforated trays
- -Use of organic acid additives
- -Improve or upgrade scrubber auxiliary equipment
- -Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

Table 5: Craig Units 1 & 2 SO<sub>2</sub> Operating Permit Limits

	S	O <sub>2</sub> limits (lb/MM	Reduction (%) Required	
	3-hr rolling	30-day rolling	90-day rolling	90-day rolling
Units 1 & 2	1.2	0.160	0.130	90

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

#### Step 2: Eliminate Technically Infeasible Options

*FGD:* Flue gas desulfurization removes SO<sub>2</sub> from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity

<sup>&</sup>lt;sup>2</sup> EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

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to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney. Colorado Ute Electric Association, which owned Craig before TriState, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. TriState upgraded these FGD systems in the 2003 – 2004 timeframe. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu.

At the Division's request, TriState submitted a SO<sub>2</sub> upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

TriState examined potential upgrades to the Craig wet FGD systems, with the following results:

-Elimination of bypass reheat: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations. After the Yampa Environmental Project (YEP) Upgrades (2003 - 2004), 100 percent of the flue gas now passes through the scrubber with no reheat and no bypassing.

-Installation of liquid distribution rings: Liquid distribution rings were not installed during the YEP; however, TriState determined that installation of perforated trays, described below, accomplished the same objective.

-Installation of perforated trays: Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of SO<sub>2</sub> by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

- -Use of organic acid additives: Organic acid additives such as Dibasic Acid (DBA) can be used to improve SO<sub>2</sub> removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:
- 1. DBA has not been tested at the very low inlet SO<sub>2</sub> concentrations seen at Craig Units 1 and 2.
- 2. DBA could cause changes in sulfite oxidation with impacts on SO<sub>2</sub> removal and solids settling and dewatering characteristics.
- 3. Installation of the perforated plate tray accomplished the same objective of increased  $SO_2$  removal.

-Improve or upgrade scrubber auxiliary equipment: YEP included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

- 1. Two vertical ball mills were installed for additional limestone processing capability for increased  $SO_2$  removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high  $SO_2$  removal rates.
- 2. Forced oxidation within the SO<sub>2</sub> removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
- 3. A ventilation system was installed for each reaction tank.
- 4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
- 5. TriState installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
- 6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO<sub>2</sub> removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
- 7. Instrumentation and controls were modified to support all of the new equipment.
- -Redesign spray header or nozzle configuration: The slurry spray distribution was modified during YEP. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, TriState and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the SO<sub>2</sub> emission limit for Craig Units 1 and 2.

# Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 - 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)

Unit	Maximum 30-day rolling emission rate	Average 30-day rolling emission rate
	(lb/MMBtu)	(lb/MMBtu)
Craig Unit	0.081	0.052

1		
Craig Unit	0.093	0.079

# Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

# Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results (98<sup>th</sup> percentile impact and improvements). Cost effectiveness in \$/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Per the April 2010 modeling protocol<sup>3</sup>, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a  $SO_2$  BART control technology on a given unit, emission rates for the other pollutants ( $NO_x$  and  $PM/PM_{10}$ ) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with  $NO_x$  emissions at 0.07 lb/MMBtu (SCR control) and  $SO_2$  emissions at 0.10 lb/MMBtu (wet FGD).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 7: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

				3-year	totals		3-year	totals	
SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	Pre- Control Days >0.5 dv	Post- Control Days >0.5 dv	∆days	Pre- Control Days >1.0 dv	Post- Control Days >1.0 dv	∆days
Max 24-	1	0.166	Mt. Zirkel	207			123		
hour	hour 2 0.161 Wildernes	Wilderness	207			123			

<sup>&</sup>lt;sup>3</sup> Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

Wet	1	0.150	207	206	1	123	123	0
FGD	2	0.150	207	207	0	123	123	0
Wet	1	0.120	207	204	3	123	123	0
FGD	2	0.120	207	204	3	123	123	0
Wet	1	0.110*			n	′a		
FGD	2	0.110*			n	⁄a		
Wet	1	0.100	207	203	4	123	123	0
FGD	2	0.100	207	203	4	123	123	0
Wet	1	0.070	207	202	5	123	122	1
FGD	2	0.070	207	203	4	123	122	1
Combo	1	0.100	207	57	150	123	12	111
Collido	2	0.100	207	37	130	123	12	111

<sup>\*</sup> Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Table 8: Visibility Results – SO<sub>2</sub> Control Options

SO2 Control Scenario Boiler(s)		SO2 Emission Rate (lb/MMBtu)*	Output (@ 98 <sup>th</sup> Percentile Impact)*	98 <sup>th</sup> Percentile Impact Improvement	98 <sup>th</sup> Percentile Improvement from Maximum	
			(dv)	(Δ dv)	(%)	
Max 24-	1	0.166	3.73			
hour	2	0.161	3.73			
Wet FGD	1	0.150	3.72	0.01	0%	
weirgd	2	0.150	3.72	0.01	0%	
W-4 ECD	1	0.120	3.70	0.02	1%	
Wet FGD	2	0.120	3.71	0.02	1%	
W-4 ECD	1	0.110*	3.70	0.03	1%	
Wet FGD	2	0.110*	3.70	0.03	1%	
W-4 ECD	1	0.100	3.69	0.03	1%	
Wet FGD	2	0.100	3.70	0.03	1%	
W-4 ECD	1	0.070	3.68	0.05	1%	
Wet FGD	2	0.070	3.68	0.05	1%	
C1	1	0.070	1 17	2.57	(00/	
Combo	2	0.070	1.17	2.56	69%	

<sup>\*</sup> Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

## Step 6: Select BART Control

There are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 and determined that a more stringent 30-day rolling SO<sub>2</sub> limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology. The tighter emission limits are achievable without additional capital investment. An SO<sub>2</sub> limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

# **B.** Filterable Particulate Matter (PM<sub>10</sub>)

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control  $PM/PM_{10}$  emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 9: Craig Units 1 and 2 Stack Test Results (2004)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM <sub>10</sub>	0.006	0.005
PM <sub>10</sub> Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM<sub>10</sub> determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

The Division has determined that the existing Unit 1 and 2 pulse jet fabric filter baghouses and the emission limit of 0.03 lb/MMBtu (PM/PM<sub>10</sub>) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM<sub>10</sub>.

# C. Nitrogen Oxide (NO<sub>x</sub>)

Step 1: Identify All Available Technologies

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TriState identified five options for NO<sub>x</sub> control:

New/modified Low NO<sub>x</sub> Burners (LNBs) with Overfire Air (OFA) system (next generation)

Advanced OFA system or Rotating overfire Air (ROFA)

Neural network system combustion controls

Selective Non-Catalytic Reduction (SNCR)

Selective Catalytic Reduction (SCR)

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

Electro-Catalytic Oxidation (ECO)®

Rich Reagent Injection (RRI)

Coal reburn +SNCR

Craig Units 1 and 2 currently have ultra-low NO<sub>x</sub> burners with over-fire air (ULNBs+OFA) installed (2004) for NO<sub>x</sub> control purposes.

# Step 2: Eliminate Technically Infeasible Options

LNBs with OFA Upgrades: TriState contracted with ACT to modify the existing Craig 1&2 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-NO<sub>x</sub> Babcock & Wilcox 4Z burners such as those in use at Craig Units 1 and 2. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that "to give a guaranteed NO<sub>x</sub> reduction, a lot more information is required." LNBs modifications with OFA upgrades appear to be technically feasible for Craig Units 1 and 2.

Advanced OFA system – rotating overfire air system (ROFA): ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

TriState contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mobotec could not give TriState a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving  $NO_x$  emission reductions from 45 to 65 % based on fuel load<sup>4</sup>. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

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<sup>&</sup>lt;sup>4</sup> Nalco-Mobotec, ROFA Technology, 1992-2009, <a href="http://www.nalcomobotec.com/technology/rofa-technology.html">http://www.nalcomobotec.com/technology/rofa-technology.html</a>

Neural network system combustion controls: TriState received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 1&2 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 1&2 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. TriState states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential  $NO_x$  reductions. Neural network system combustion controls appear to be technically feasible for Craig Units 1 and 2.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO<sub>x</sub> reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO<sub>x</sub> to nitrogen and water. NO<sub>x</sub> reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO<sub>x</sub>, can have a significant impact on economics, with higher levels of NO<sub>x</sub> reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion  $NO_x$  control technology. In retrofit SCR systems, vaporized ammonia (NH<sub>3</sub>) injected into the flue gas stream acts as a reducing agent, achieving  $NO_x$  emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The  $NO_x$  and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a  $NO_x$  reduction basis) with very low ammonia slip.

While a lower controlled  $NO_x$  emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled  $NO_x$  value is more expected, although TriState asserts that the units cannot achieve below 0.08 lb/MMBtu. See "TriState BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

*ECO*®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not

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been demonstrated on a full-size pulverized coal-fired boiler<sup>5</sup> and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO<sub>x</sub> reducing agents in a staged lower furnace to reduce the formation of NO<sub>x</sub>, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO<sub>x</sub> reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers<sup>6</sup> and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO<sub>x</sub> burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% NO<sub>x</sub> reductions (based on actual emissions) on Units 1 and 2, respectively.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO<sub>x</sub> emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO<sub>x</sub> emissions by 93% or well below 0.1 lb/MMBtu<sup>7</sup>. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

## Step 3: Evaluate Control Effectiveness of Each Remaining Technology

TriState provided the Division annual average control estimates. In the Division's experience and other state BART proposals, 8 30-day NO<sub>x</sub> rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Units 1 and 2 to determine control efficiencies and annual reductions.

LNBs with OFA Upgrades: TriState noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% NO<sub>x</sub> reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0-2 % control. B&V explains that the reduction in

<sup>&</sup>lt;sup>5</sup> Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO\_overview.aspx <sup>6</sup> Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

<sup>&</sup>lt;sup>7</sup> Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

<sup>&</sup>lt;sup>8</sup> State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low  $NO_x$  burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

Neural network system combustion controls: TriState noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5-15% NO<sub>x</sub> reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0-5% control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

SNCR: TriState stated in the May 14, 2010 submittal that based on the boiler configuration, TriState could expect a continuous NO<sub>x</sub> reduction performance with SNCR technology in the range of 10 - 15%. This is based on TriState's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. TriState staff conducted a visit to First Energy's Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO<sub>x</sub> control. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010. The results of this study varied significantly depending on what coal type was utilized and were applicable for Craig Unit 1. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers approximately 15% to be a reasonable control effectiveness for SNCR.

*SCR:* TriState stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. TriState did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu<sup>9</sup>or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO<sub>x</sub> reduction efficiencies greater than 85% with emission

<sup>&</sup>lt;sup>9</sup> Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.

rates between 0.04 and 0.07 lb/MMBtu (during the ozone season). <sup>10</sup> EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO<sub>x</sub> emission reductions. However, an appropriate margin of error must be applied when evaluating SCR. The design goal emission rate may be lower than the permitted limit to ensure that unnecessary non-compliance periods do not become an issue, The Division may evaluate tighter emission limits in future RH planning periods if SCR is determined to be BART for either Craig Unit 1 or 2. At this time, the Division accepts Tri-State's estimates of 0.08 lb/MMBtu on a 30-day rolling average. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted TriState's estimate to 0.07 lb/MMBtu based on the reasoning above.

**Table 10: SCR Control Efficiency Comparison** 

Unit	Baseline	Control Efficiency (%)		Resultant Emissi	ions (lb/MMBtu)
	(lb/MMBtu)	TriState Division		TriState Estimate	Division Estimate
		Estimate	Estimate	(annual average)	(annual average)
Craig	0.278	71.4	74.9	0.080	0.070
Unit 1					
Craig	0.271	70.5	74.0	0.080	0.070
Unit 2					

Table 11 summarizes each available technology and technical feasibility for NO<sub>x</sub> control.

Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission	Technically Feasible?
	Reduction	(Y = yes, N = no)
	Potential (%)	
Low NO <sub>x</sub> Burners/Ultra-low	10-30%	Y – installed
NO <sub>x</sub> burners (LNB/ULNB)		
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air	5-40%	Y – installed
(OFA)		
Ultra-Low NO <sub>x</sub> Burner	0 - 2%	Y
(ULNB)	(TriState)	
Upgrade/Refinements		
Neural network system	0 - 5%	Y
	(TriState)	
SNCR	~15%	Y
Rotating overfire air (ROFA)	45 – 65%	N
SCR	75 – 90%	Y
Electro-Catalytic Oxidation	n/a	N
(ECO)®		
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

# Cost of Compliance

<sup>&</sup>lt;sup>10</sup> Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Low NO<sub>x</sub> burner upgrades: Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low NO<sub>x</sub> burners with overfire air. Ultra-low NO<sub>x</sub> burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000. Tri-State estimates that the initial cost of combustion control refinement at about \$2,200,000 with an annualized 20-year cost of \$122,000. The Division notes that the Craig units already have ultra-low NO<sub>x</sub> burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

Neural network system: TriState did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that TriState contacted. It is unknown why TriState will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about \$800,000 with an annualized 20-year cost of \$280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

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 TriState-estimated SNCR costs for operating expenses are 67% for Craig Units 1 and 2 (individually). Since SNCR is an operating expense-driven technology, its cost varies directly with NO<sub>x</sub> 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 NO<sub>x</sub> level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.  $^{14}$ 

The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately \$4,877 and \$4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 - 0.65 lb/MMBtu and emission reductions of 30 - 50% as costing \$590 - \$1,100 per ton of NO<sub>x</sub> reduced, depending on initial

<sup>&</sup>lt;sup>11</sup> Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.

<sup>&</sup>lt;sup>12</sup> NeuCo White Papers and Case Studies. <a href="http://www.neuco.net/library/case-studies/default.cfm">http://www.neuco.net/library/case-studies/default.cfm</a> and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."

<sup>&</sup>lt;sup>13</sup> ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO<sub>x</sub> Emissions." Washington, D.C. 2000.

<sup>&</sup>lt;sup>14</sup> EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

capital costs and capacity factor. <sup>15,16</sup> It should be noted that TriState is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO<sub>x</sub> reduced. <sup>17</sup> On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately \$2,500 per ton. TriState and the Division's revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from TriState. The costs for these two items are higher than other Colorado facility estimates. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts TriState's capital and operation/maintenance costs for this analysis..

*SCR:* Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO<sub>x</sub> emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing \$1,700 - \$3,200 per ton of NO<sub>x</sub> reduced, depending on initial capital costs and capacity factor. <sup>18,19</sup> <sup>20,21</sup> It should be noted that TriState is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. TriState's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately \$7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 12, Table 13, Table 14, and Table 15 depict controlled NO<sub>x</sub> emissions and control cost comparisons.

Table 12: Craig Unit 1 Control Resultant NO<sub>x</sub> Emissions

Alternative	Control	Resultant Emissions					
	Efficiency (%)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)			
Baseline		5,190	0.278				
Combustion control refinements	2	5,087	0.273	0.31			
Neural network system	5	4,931	0.264	0.30			

<sup>&</sup>lt;sup>15</sup> Neuffer, Bill – ESD/OAQPS, 2003. "NO<sub>x</sub> Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

<sup>&</sup>lt;sup>16</sup> Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <a href="http://www.epa.gov/ttn/catc/dir1/fsncr.pdf">http://www.epa.gov/ttn/catc/dir1/fsncr.pdf</a>
 Neuffer, Bill – ESD/OAQPS, 2003. "NO<sub>x</sub> Controls for Existing Utility Boilers." <a href="http://www.epa.gov/ttn/nsr/gen/u3-26.pdf">http://www.epa.gov/ttn/nsr/gen/u3-26.pdf</a>

<sup>&</sup>lt;sup>19</sup> Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

<sup>&</sup>lt;sup>20</sup> Neuffer, Bill – ESD/OAQPS, 2003. "NO<sub>x</sub> Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

<sup>&</sup>lt;sup>21</sup> Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

SNCR	15	4,412	0.236	0.27
SCR	74.9	1,305	0.070	0.08

Table 13: Craig Unit 2 Control Resultant  $NO_x$  Emissions

Alternative	Control	Resultant Emissions				
	Efficiency (%)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)		
Baseline		5,372	0.271			
Combustion control refinements	2	5,264	0.265	0.31		
Neural network system	5		0.257	0.30		
SNCR	15	4,566	0.230	0.27		
SCR	74	1,397	0.070	0.07		

Table 14: Craig Unit 1 NO<sub>x</sub> Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	
Combustion control refinements	104	\$122,000	\$1,175	\$1,175
Neural network system	260	\$280,000	\$1,079	\$1,015
SNCR	779	\$3,797,000	\$4,877	\$6,776
SCR	3,893	\$25,036,709	\$6,432	\$6,708

Table 15: Craig Unit 2NO<sub>v</sub> Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	
Combustion control refinements	107	\$122,000	\$1,136	\$1,136
Neural network system	269	\$280,000	\$1,043	\$980
SNCR	806	\$3,797,000	\$4,712	\$4,712
SCR	3,975	\$25,036,709	\$6,299	\$6,702

# **Energy and Non-Air Quality Impacts**

LNB Upgrades/Neural network system(s): There are no known non-air quality impacts associated with upgrades on low- $NO_x$  burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

*SNCR/SCR*: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

## Remaining Useful Life

TriState asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

## Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98<sup>th</sup> percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol<sup>22</sup>, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO<sub>2</sub> BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than

<sup>&</sup>lt;sup>22</sup> Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with  $NO_x$  emissions at 0.07 lb/MMBtu (SCR control) and  $SO_2$  emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 16: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

		NO			r totals		3-year	r totals	
NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	Pre- Control Days >0.5 dv	Post- Control Days >0.5 dv	Δdays	Pre- Control Days >1.0 dv	Post- Control Days >1.0 dv	Δdays
Max 24-	1	0.352		207			122		
hour	2	0.345		207			123		
SNCR	1	0.236		207	192	15	123	123	0
	2	0.230	Mt. Zirkel	207	194	13	123	123	0
SCR	1	0.07	Wilderness	207	165	42	123	123	0
	2	0.07		207	166	41	123	123	0
	1	0.07							
Combo	2	0.07		207	57	150	123	12	111

Table 17: Visibility Results – NO., Control Options

	Table 17. Visibility Results – NO <sub>x</sub> Control Options							
NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98 <sup>th</sup> Percentile Impact)	98 <sup>th</sup> Percentile Impact Improvement	98 <sup>th</sup> Percentile Improvement from Maximum	Cost Effectiveness		
		,	(dv)	$(\Delta dv)$	(%)	(\$/dv)		
Max 24-	1	0.352	3.73					
hour	2	0.345						
SNCR	1	0.236	3.42	0.31	8%	\$12,327,922		
	2	0.230	3.42	0.31	8%	\$12,327,922		
SCR	1	0.07	2.72	1.01	27%	\$24,887,384		
	2	0.07	2.75	0.98	26%	\$25,652,365		
	1	0.07		2.56	69%			
Combo	2	0.07	1.17			\$19,537,034		

## Step 6: Select BART Control

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

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

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average) Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

For SNCR at Units 1 and 2, 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 1: \$4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: \$4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

Per Section 308(e)(2) of EPA's Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent  $NO_x$  emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These  $NO_x$  emission rates are as follows:

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average) Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu  $NO_x$  emission rate equates to a 14% control and a  $NO_x$  reduction of 727 tons per year, which is slightly less than the 15% control and a  $NO_x$  reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination. Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a  $NO_x$  reduction of 3,975 tons per year, which is much greater than the 15% control and a  $NO_x$  reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination. The total  $NO_x$  emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total  $NO_x$  emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig

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Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the NO<sub>x</sub> emission reduction associated with both units (Craig 1 & 2) in contrast to the existing NO<sub>x</sub> rates, presumptive BART NO<sub>x</sub> rate, source-by-source determination, and the final RH determination to determine the total NO<sub>x</sub> reduction benefit. In the below table, the existing NO<sub>x</sub> emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in NO<sub>x</sub> emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.