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.

Units 1 & 2: 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_2) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfired air for minimization of NO_x emissions. The FGD and ultra low NO_x 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).

Unit 3: 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_2 and low-NO_x burners with overfired 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_x 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.

Table 1 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 Rating, MMBtu/Hr for coal	4,417	4,417
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_{10} – Pulse Jet Fabric Filter Baghouse NO_x – Ultra-low NO_x Burners with Over-Fire Air SO_2 – Wet Limestone FGD All updated control equipment commenced full operations in 2004.	PM/PM_{10} – Pulse Jet Fabric Filter Baghouse NO_x – Ultra-low NO_x Burners with Over-Fire Air SO_2 – Wet Limestone FGD All updated control equipment commenced full operations in 2004.
Emissions Reduction (%)*	NO_x – 23.8% /53.9% SO_2 – 77.6%/93.8% PM – 99.6% PM_{10} – 99.4%	NO_x – 29.5%/54.7% SO_2 – 79.5%/93.8% PM – 99.9% PM_{10} – 99.5%

*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_{10}., 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_x, SO_2, PM_{10}), and in existence 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 "Tri-State 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

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (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***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**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.
***The PM_{10} emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

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 sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. . 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_x-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_x 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_2O (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[1]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	12	16.9	73.9	17.0
Unit 2	12	16.1	71.1	16.4

*SO_2 and PM/PM_{10} 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_2)

Step 1: Identify All Available Technologies

Wet FGD Upgrades – As discussed in EPA's BART Guidelines[2], 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_2 Operating Permit Limits

	SO_2 limits (lb/MMBtu)			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).

[1] 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
[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 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 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 Tri-State, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. Tri-State 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, Tri-State submitted a SO_2 upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

Tri-State 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, Tri-State 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_2 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_2 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_2 concentrations seen at Craig Units 1 and 2.

2. DBA could cause changes in sulfite oxidation with impacts on SO_2 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_2 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. Tri-State 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_2 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, Tri-State 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_2 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 (lb/MMBtu)	Average 30-day rolling emission rate (lb/MMBtu)
Craig Unit 1	0.081	0.052
Craig Unit 2	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^{th} 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[3], 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).

[3] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

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

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				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-hour	1	0.166	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.161							
Wet FGD	1	0.150		207	206	1	123	123	0
	2	0.150		207	207	0	123	123	0
Wet FGD	1	0.120		207	204	3	123	123	0
	2	0.120		207	204	3	123	123	0
Wet FGD	1	0.110*		n/a					
	2	0.110*		n/a					
Wet FGD	1	0.100		207	203	4	123	123	0
	2	0.100		207	203	4	123	123	0
Wet FGD	1	0.070		207	202	5	123	122	1
	2	0.070		207	203	4	123	122	1
Combo	1	0.100		207	57	150	123	12	111
	2	0.100							

* 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_2 Control Options

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

* 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_2 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_2 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_{10})

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_{10}	0.006	0.005
PM_{10} Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} 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_{10}) 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_{10}.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

Tri-State identified five options for NO_x control:
New/modified Low NO_x Burners (LNBs) with Overfired Air (OFA) system (next generation)
Advanced OFA system or Rotating overfired 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_x burners with over-fire air (ULNBs+OFA) installed (2004) for NO_x control purposes.

Step 2: Eliminate Technically Infeasible Options

LNBs with OFA Upgrades: Tri-State 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_x 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_x 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 overfired 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.

Tri-State contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mobotec could not give Tri-State 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[4]. 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.

Neural network system combustion controls: Tri-State 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. Tri-State 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.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x 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_x to nitrogen and water. NO_x 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_x, can have a significant impact on economics, with higher levels of NO_x 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_3) 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 Tri-State asserts that the units cannot achieve below 0.08 lb/MMBtu. See "Tri-State 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 been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, 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_x reductions. The combustion process is then completed with the use of overfired air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

[5] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[6] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO_x 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_x 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_x 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_x emissions by 93% or well below 0.1 lb/MMBtu[7]. 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

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[8] 30-day NO_x 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: Tri-State 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_x 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 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: Tri-State 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_x 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.

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[7] 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

[8] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

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: Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State'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. Tri-State staff conducted a visit to First Energy's Eastlake and W.H. 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_x 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: Tri-State 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. Tri-State 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[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[10] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x 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. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

[9] 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.
[10] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Table 10: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		Tri-State Estimate	Division Estimate	Tri-State Estimate (annual average)	Division Estimate (annual average)
Craig Unit 1	0.278	71.4	74.9	0.080	0.070
Craig Unit 2	0.271	70.5	74.0	0.080	0.070

Table 11 summarizes each available technology and technical feasibility for NO_x control.

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

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

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Low NO_x 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_x burners with overfired air. Ultra-low NO_x 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.[11] 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_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 refinement cost estimates from December 8, 2010.

[11] 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.

Neural network system: Tri-State 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 Tri-State contacted.[12] It is unknown why Tri-State 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.[13] The Tri-State-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_x 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_x 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_x reduced, depending on initial capital costs and capacity factor.[15,16] It should be noted that Tri-State 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_x reduced.[17] 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. Tri-State 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 Tri-State. The costs for these two items are higher than other Colorado facility estimates.

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[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."

[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[15] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] 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.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts Tri-State's capital and operation/maintenance costs for this analysis.

SCR: Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO_x 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_x reduced, depending on initial capital costs and capacity factor.[18,19] [20,21] It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State'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_x emissions and control cost comparisons.

Table 12: Craig Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		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
SNCR	15	4,412	0.236	0.27
SCR	78.0	1,142	0.061	0.070

[18] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] 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.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] 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.

Table 13: Craig Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		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	0.081

Table 14: Craig Unit 1 NO_x 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	4,048	$25,036,709	$6,184	$6,394

Table 15: Craig Unit 2 NO_x 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	$6,298	$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

Tri-State 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^{th} 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[22], 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 and other BART-eligible units are held constant at pre-control levels.

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

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 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

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				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-hour	1	0.352	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.345							
SNCR	1	0.236		207	192	15	123	123	0
	2	0.230		207	194	13	123	123	0
SCR	1	0.07		207	165	42	123	123	0
	2	0.07		207	166	41	123	123	0
Combo	1	0.07		207	57	150	123	12	111
	2	0.07							

Table 17: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1	0.352	3.73	---	---	---
	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	0.08	2.79	0.94	25%	$26,691,207
Combo	1	0.07	1.17	2.56	69%	$19,537,034
	2	0.07				

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 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 the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that they can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan. The criteria in Chapter 6 guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the notable visibility improvements, the reasonable dollars per ton control costs, and the support of Tri-State for installation of SCR at Units 1 and 2.

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

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. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's decision to approve Colorado's Regional Plan.

This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): Table 18 below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination In Table 19 below, an assumed amortization period of eight years of operation[23] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[24]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

Table 18: Craig Unit 1 NOx Cost Comparisons (4 years, 4 months of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$6,172,522	$7,928
SCR	4,048	$64,106,699	$15,835

Table 19: Craig Unit 1 NOx Cost Comparisons (8 years of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$4,755,842	$6,109
SCR	4,048	$41,476,535	$10,245

Based on this assessment, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life; or
Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31,

[23] Operation period begins calendar year 2018 (December 31, 2017).
[24] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until closing or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination.

Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.