Reasonable Progress Analysis of Control Options For Tri-State Generation & Transmission Association, Inc. – Craig Station Unit 3

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100202
Boiler Type:	Three Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2) and one front-fired (Unit 3)

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. Unit 3, rated at 4,600 MMBtu/hour (net 408 MW) was placed in service in 1984.

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 overfire 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 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_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.

For this analysis, the Division also relied on the existing Construction permit, historical information regarding Craig Station, and information about similar facilities to determine RP for NO_x, SO_2, and PM_{10}. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must considered in making BART and RP determinations are largely the same. Units 1 and 2 are considered BART-eligible, being industrial boilers

with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1] ."

These levels are as follows:

- NO_x – 40 tons per year
- SO_2 – 40 tons per year
- PM_{10} – 15 tons per year

Boiler 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010. **Error! Reference source not found.** depicts technical information for Unit 3 at Craig Station.

Table 1: Craig Unit 3 Technical Information

	Unit 3
Placed in Service	1984
Gross Boiler Rating, MMBtu/Hr for coal	4,600
Electrical Power Rating, Net Megawatts	408
Description	Babcock & Wilcox coal, dry bottom boiler - Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization
Air Pollution Control Equipment	PM/PM_{10} – Pulse Jet Fabric Filter Baghouse (1984 – upgraded between 2007 and 2009) NO_x – Low NO_x Burners with Over-Fire Air (upgraded between 2007 and 2009) SO_2 – Dry Limestone FGD (1984 – upgraded between 2007 and 2009) Existing turbine generator replaced with larger unit completed in May 2009.
Emissions Reduction (%)*	NO_x – 19.0%/38.8%* SO_2 – 80.9%

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

	PM – 99.8% PM_{10} – 99.6%

*Emissions Reduction estimated by comparing pre-control upgrade 2006-2008 CAMD data to AP-42 emission factor 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 (June 2009 – June 2010). 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.

II. Source Emissions

Table 2 summarizes the NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA's CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's APEN's submitted by the facility and as applicable, EPA's CAMD Database (primarily for the Unit 101 boiler and the turbines).

Table 2. Summary of 2006 - 2008 Averaged Emissions – Craig Station

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
16,942	3,769	363

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Craig Station

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 1	SO_2 (tons)	865.1	1053.0	990.5	969.5
	SO_2 (lb/ MMBtu)	0.06	0.06	0.06	0.06
	NO_x (tons)	4665.7	5817.3	5056.9	5180.0
	NO_x (lb/ MMBtu)	0.34	0.32	0.30	0.32
	PM (tons)	92.9	107.3	101.1	100.4
	PM (lb/ MMBtu)	0.007	0.006	0.006	0.006
Unit 2	SO_2 (tons)	999.6	797.1	1149.1	981.9
	SO_2 (lb/ MMBtu)	0.05	0.05	0.06	0.06
	NO_x (tons)	5548.7	4965.7	5566.4	5360.3
	NO_x (lb/ MMBtu)	0.30	0.32	0.30	0.31
	PM (tons)	90.7	81.9	87.5	86.7
	PM (lb/ MMBtu)	0.005	0.005	0.005	0.005
Unit 3	SO_2 (tons)	1721.3	1948.5	1782.6	1817.5
	SO_2 (lb/ MMBtu)	0.10	0.11	0.11	0.10
	NO_x (tons)	6592.1	6670.1	5943.9	6402.0
	NO_x (lb/ MMBtu)	0.38	0.36	0.35	0.37
	PM (tons)	70.4	71.8	67.7	70.0
	PM (lb/ MMBtu)	0.004	0.004	0.004	0.004
Auxiliary Boiler (130 MMBtu/hr) Fuel Oil Boiler	*SO_2 (tons)*	*0*	*0*	*0*	*0*
	SO_2 (lb/ MMBtu)	*0*	*0*	*0*	*0*
	NO_x (tons)	*0*	*0*	*0*	*0*

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
	NO_x (lb/ MMBtu)	*0*	*0*	*0*	*0*
	PM (tons)	*0*	*0*	*0*	*0*
	PM (lb/ MMBtu)	*0*	*0*	*0*	*0*
F101a – Coal Hauling – Units 1 & 2	*PM (tons)*	*8.15*	*8.15*	*11.39*	*9.23*
F101b – Coal Unloading to Grizzly – Units 1 & 2	*PM (tons)*	*0.04*	*0.04*	*0.05*	*0.04*
F101c – Coal Surge Pile	*PM (tons)*	*0.05*	*0.05*	*0.05*	*0.05*
S101d – Primary Coal Crushing – Units 1 & 2	*PM (tons)*	*0.18*	*0.18*	*0.23*	*0.20*
S101e – Secondary Coal Crushing Bldg – Units 1 & 2	*PM (tons)*	*0.46*	*0.46*	*0.56*	*0.49*
S101f – Common Coal Transfer Bldg Belt A	*PM (tons)*	*0.001*	*0.001*	*0.0013*	*0.0011*
S101g – Common Coal Transfer Bldg Belt B	*PM (tons)*	*0.001*	*0.001*	*0.0013*	*0.0011*
S101h – Coal Stackout Building – Units 1 & 2	*PM (tons)*	*0.002*	*0.002*	*0.0025*	*0.0022*
S101i - Coal Stackout – Units 1 & 2	*PM (tons)*	*0.051*	*0.051*	*0.063*	*0.055*
F101 j -Coal Storage Piles – Units 1 & 2	*PM (tons)*	*0.63*	*0.63*	*0.63*	*0.63*
S101k – Coal Reclaim A – Units 1 & 2	*PM (tons)*	*0.0018*	*0.0018*	*0.0019*	*0.0018*
S101l – Coal Reclaim B – Units 1 & 2	*PM (tons)*	*0.0018*	*0.0018*	*0.0019*	*0.0018*
S101m – coal Tripper Deck & Silos – Units 1 & 2	*PM (tons)*	*0.0036*	*0.0036*	*0.0038*	*0.0037*
S101n – Common Coal Drive House	*PM (tons)*	*0.0036*	*0.0036*	*0.0038*	*0.0037*
S203a – Fly Ash Storage Silo A – Units 1 & 2	*PM (tons)*	*0.0047*	*0.0047*	*0.002*	*0.0038*
S203b – Fly Ash Storage Silo B – Units 1 & 2	*PM (tons)*	*0.0047*	*0.0047*	*0.002*	*0.0038*
F203c – Fly Ash Truck Loading – Units 1 & 2	*PM (tons)*	*0.0079*	*0.0079*	*0.0034*	*0.0064*
P204 – Ash Hauling & Storage – Unit 3	PM (tons)	62.2	62.2	62.2	62.2
P201 – Limestone Hauling	PM (tons)	14.7	14.7	17.5	15.6
F102a – Coal Train Unloading – Unit 3	*PM (tons)*	*0.0607*	*0.0607*	*0.0676*	*0.063*
S102b/c – Coal Conveyor Portal Building – Unit 3	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102d – Secondary Coal Crushing (2 crushers0 – Unit 3	*PM (tons)*	*0.68*	*0.68*	*0.76*	*0.71*
S102e – Coal Stackout Building – Unit 3	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
F102f – Coal Stackout – Unit 3	*PM (tons)*	*0.076*	*0.076*	*0.085*	*0.078*

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
F102g – Coal Storage Pile – Unit 3	*PM (tons)*	*0.24*	*0.24*	*0.24*	*0.24*
S102h – Coal Reclaim System – Unit 3	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102k – Common Coal Transfer Building Extension	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102n – Common Coal Drive House	*PM (tons)*	*0.003*	*0.003*	*0.0034*	*0.0031*
S102i – Coal Tripper Deck and Silos – Unit 3	*PM (tons)*	*0.0018*	*0.0018*	*0.0018*	*0.0018*
S102j – Loadout Coal to Railcars – Unit 3	*PM (tons)*	*0*	*0*	*0*	*0*
F205a – Ash Hauling to "Landfill" (Outage Waste to Trapper)	*PM (tons)*	*0.114*	*0.114*	*0.114*	*0.114*
F205b – Ash and Wet Waste Hauling to/from Decant Basin	*PM (tons)*	*0.676*	*0.676*	*0.676*	*0.676*
F205c – Ash Unloading at "Landfill" (Outage Waste) & Ash Unloading at Decant Basin	*PM (tons)*	*0.0024*	*0.0024*	*0.0024*	*0.0024*
F205d – Wet Waste Unloading at Decant Basin	*PM (tons)*	*0*	*0*	*0*	*0*
F202a – Lime Hauling (trucks)	*PM (tons)*	*0*	*0*	*0*	*0*
S202b – Lime Unloading – Unit 3	*PM (tons)*	*0.0011*	*0.0011*	*0.0012*	*0.0011*
S202c – Lime Conveying & Silo – Unit 3	*PM (tons)*	*0.0011*	*0.0011*	*0.0012*	*0.0011*
S202d – Lime Day Bin	*PM (tons)*	*0.0011*	*0.0011*	*0.0012*	*0.0011*
S401/2 – Cooling Towers – Units 1 & 2	*PM (tons)*	*10.3*	*10.3*	*10.3*	*10.3*
Auxiliary Boiler	*PM (tons)*	*0*	*0*	*0*	*0*
S403 - Cooling Tower – Unit 3	*PM (tons)*	*5.8*	*5.2*	*5.2*	*5.4*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day NO_x rolling averages for the boilers are estimated to be 5-15% higher than the annual average emission rate.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Tri-State estimated that a realistic depiction of anticipated annual emissions for Unit 3, or "Baseline" Emissions", to be conservative, was the average of 30-day averages from 2009, or 0.33 lb/MMBtu for NO_x. Tri-State noted that this baseline reflects the recent PSD permit limit of 6,752 tons associated with a 2009 turbine upgrade. This baseline reflects the low-NO_x burners and overfire air installed at Craig 3 in 2009. The Division notes that the 2006 – 2008 baseline period used for other RP and BART sources is not reasonable for Craig Unit 3 due to the recent upgrades. The Division also used the recent PSD permit limit of 6,752 tons for NO_x and 2,125 tons for SO_2 to determine a baseline.

The notable difference is that the Division used the average capacity factor (based on heat input) from 2006 – 2008 to determine the baseline emissions, resulting in 0.28 lb/MMBtu for NO_x and 0.09 lb/MMBtu for SO_2. Craig Unit 3 ran at an average of 86.4% capacity (based on heat input) from 2006 – 2008, thus this factor is assumed to be a reasonable baseline for this planning period. 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 4.

Table 4: Tri-State Craig Unit 3 Baseline Emissions

Pollutant	Unit 3	
	Annual Emissions* (tpy)	Average Emissions (lb/MMBtu)
NO_x	5,693	0.283
SO_2	1,792	0.089
PM_{10}	148**	0.007**

*The Division calculated annual (tpy and lb/MMBtu) NO_x and SO_2 emissions using 2006 – 2008 capacity factor and current PSD permit limits.
**The PM_{10} emissions and emissions factor are from August 2009 stack test data; PM_{10} current construction permit annual emission limit is 403 tons/year and 0.012 lb/MMBtu.

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. 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_x-forming characteristics, Craig 3 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 3 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 6. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals. The actual APEN coal specifications (2006 – 2008) are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Craig Unit 3	10,224	0.39	6.47

Table 6: 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 7. 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 7: Uncontrolled emission factors for Craig BART-eligible sources[2]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 3	12	14.7	64.7	14.9

*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. Reasonable Progress Evaluation of Unit 3

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

The Division requested that Tri-State evaluate the option below, and received relevant information for this request on June 4, 2010:

Dry FGD upgrades

As discussed in EPA's BART Guidelines[3], 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. However, upgrades need to be considered for the scrubber if technically feasible. These upgrades include:

-Use of performance additives
-Use of more reactive sorbent
-Increase the pulverization level of sorbent
-Engineering redesign of atomizer or slurry injection system

The current PSD permit SO_2 limits are depicted in Table 8.

Table 8: Craig Unit 3 SO_2 PSD Permit Limits

	SO_2 limits (lb/MMBtu) Calendar day average	Reduction (%) Required 30-day rolling	Annual Emission Limit (tons/year)
Unit 3	0.20*	80	2,125

*May be exceeded once during any calendar month.

[2] 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

[3] 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

Dry Flue Gas Desulfurization (FGD) Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power plants[4]. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures SO_2 by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and then collected in a particulate control device.

Craig Unit 3 was installed in 1984 with a "Spray Dryer Removal System" in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for SO_2 removal from the gaseous emission stream of a utility boiler. Tri-State has since upgraded this system (between 2007 and 2009) and currently achieves greater than 80% SO_2 removal, with an actual annual average of approximately 0.09 lb/MMBtu. This system exceeds EPA's presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu[5]. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA's RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to "Division RBLC Analysis" for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of SO_2 emissions found that lime spray drying processes have a median design efficiency of 90%[6] .

The BART Guidelines note potential upgrades for dry scrubbing systems[7]. These upgrades include:

-*Use of performance additives*
-*Use of more reactive sorbent*
-*Increase the pulverization level of sorbent*
-*Engineering redesign of atomizer or slurry injection system*

Tri-State examined BART-guideline dry scrubbing potential upgrades, with the following results:

-*Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. Tri-State and the Division are not aware of SO_2 scrubber performance additives applicable or commercially available for the Unit 3 SDA system.

[4] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.
[5] Colorado Operating Permit 96OPLR142 pg. 5 – SO_2 30-day rolling average limit is 0.13 lb/MMBtu.
[6] EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.
[7] EPA, 2005. Federal Register, 40 CFR Part 51. Regional haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. Pgs. 39171.

-*Use of more reactive sorbent/Increase the pulverization level of sorbent*: The purchase and installation of two new vertical ball mill slakers improved the ability to supply high quality slaked (hydrated) lime. A higher quality slaked lime slurry means a more reactive sorbent. Typically, slakers are not designed for particle size reduction as part of the slaking process. However, the new vertical ball mill slakers are particularly suited for slaking lime that is a mixture of commercial peblle lime and lime fines. Fines are generated at the Craig facility in the pneumatic lime handling system. Therefore, the Division concurs that Tri-State cannot use a more reactive sorbent or increase the pulverization level of sorbent.

-*Engineering redesign of atomizer or slurry injection system*: Both the slaked lime slurry and recycled ash slurry preparation and delivery systems were redesigned to improve overall performance and reliability. The improved system allows for slurry pressure control at both the individual reactor level and for each slurry injection header level on each reactor. Tri-State notes that consistent control of slurry parameters (pressure, flow, composition) promotes consistent and reliable SO2 removal performance. The Division concurs that with the recent redesign of the slurry injection system and expansion to two trains of recycled ash slurry preparation, no further redesigns are possible at this time.

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Unit 3. However, the Division has evaluated the option of tightening the SO_2 emission limit for Craig Unit 3.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limit on Craig Unit 3 has been evaluated by the Division. The Division analyzed the period after Tri-State upgraded the turbine (post-control: June 2009 – June 2010) against baseline emissions (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 9, to determine potential control effectiveness, if any. Additionally, the Division evaluated the baseline heat input, capacity factor, and hours of operation pre-upgrade (2006 – 2008) and post-upgrade (June 2009 – June 2010) to evaluate whether the data was consistent with baseline information, and whether there was enough information to determine if a tighter emission limit is warranted, in Table 10. This information allows the Division to set a more relevant emission limit for Craig Unit 3 using representative actual emissions.

Table 9: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)

Unit and Timeline	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate post-control (lb/MMBtu)
Craig Unit 3 – post control (June 2009 – June 2010)	0.1350	0.1081
Craig Unit 3 – pre-control (2006 – 2008)	0.1412	0.1088

Table 10: Craig Unit 3 30-day rolling emission rates (baseline 2006 - 2008)

Unit and Timeline	Capacity Factor (Heat Input %)	Hours of Operation (% of total possible operating hours)
Craig Unit 3 – June – December 2009	98.1%	95.5%
Craig Unit 3 – January – June 2010	89.7%	96.1%
Craig Unit 3 – June 2009 – June 2010 Average	93.9%	95.8%
Craig Unit 3 – pre-control (2006 – 2008)	86.4%	96.3%

The Division notes that there are not significant differences between the maximum or average 30-day rolling emissions before and after the turbine and control upgrades. Similarly, the capacity factor and hours of operation do not change discernibly. Therefore, the Division concludes that post-upgrade operations may be used in determining a tighter SO_2 emission limit in this reasonable progress.

Table 11 summarizes each available technology options and technical feasibility for SO_2 control on Craig Unit 3.

Table 11: Craig Unit 3 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90%[8]	Y – not evaluated
Dry FGD	70 – 90%	Y - installed
DSI (Trona)	60-65%	Y – not evaluated, will not provide further SO2 control
Fuel switching – different coal type	None	Y – will not provide further SO2 control
Use of performance additives	None	N
Use of more reactive sorbent	None	N
Increase the pulverization level of sorbent	None	N
Engineering redesign of atomizer or slurry injection system	None	N

[8] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance
A more stringent emission limit is not anticipated to result in any increased costs. Thus, this factor does not influence the selection of controls.

Factor 2: Time Necessary for Compliance
A more stringent emission limit is not anticipated to result in any system upgrades or changes and can be implemented as soon as the SIP is approved. Thus, this factor does not influence the selection of controls.

Factor 3: Energy and Non-Air Quality Impacts
There is not any negative energy or non-air quality impacts related to a more stringent emission limit. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life
Tri-State asserts that there are no near-term limitations on the useful of this boiler, 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 (optional): 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 12 shows the number of days pre- and post-control. Table 13 depicts the visibility results (98th percentile impact and improvements). Cost effectiveness in $/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Table 12: 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 SO2 rates	3	0.326	Mt. Zirkel Wilderness	239	---	---	173	---	---
Dry FGD	3	0.150		239	233	6	173	170	3
Dry FGD	3	0.070		239	230	9	173	168	5

Table 13: 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 SO2 rates	3	0.326	5.20	---	---
Dry FGD	3	0.150	4.94	0.26	5%
Dry FGD	3	0.070	4.82	0.38	7%

Step 6: Select RP Control

Therefore, there are no technically feasible upgrade options for Craig Station Unit 3. However, the state evaluated the option of tightening the emission limit for Craig Unit 3 and determined that a more stringent 30-day rolling SO_2 limit of 0.15 lbs/MMBtu represents an appropriate and reasonable level of emissions control for this dry FGD control technology. Upon review of 2009 emissions data from EPA's Clean Air Markets Division website, the state has determined that this emissions rate is achievable without additional capital investment.

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP is dry FGD controls at the following SO2 emission rates:

Craig Unit 3: 0.15 lb/MMBtu (30-day rolling average)

An SO2 limit lower than 0.15 lbs/MMBtu would not result in significant visibility improvement (less than 0.2 delta deciview) and would likely result in frequent non-compliance events and, thus, is not reasonable.

B. Filterable Particulate Matter (PM_{10})

Craig Unit 3 is 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 14 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >95% control. The current Colorado construction permit limit is 0.013 lb/MMBtu for filterable PM emissions and 0.012 lb/MMBtu for filterable PM_{10} emissions and also limits total PM and PM_{10} (filterable and condensable) emissions to 0.022 and 0.020 lb/MMBtu respectively (Condition 4). 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 14: Craig Unit 3 Stack Test Results (August 2009)

Pollutant	Unit 3 (lb/MMBtu)
Total PM	0.013
Filterable PM	0.0091
Condensable PM	0.0035
Total PM_{10}	0.007
Filterable PM_{10}	0.0035
Condensable PM_{10}	0.0035
PM Control efficiency	99.5%
PM_{10} Control efficiency	98.8%

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.

The State has determined that the existing Unit 3 fabric filter baghouse and regulatory emissions limit of 0.013 (filterable PM) and 0.012 lb/MMBtu (PM10) represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP 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 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

Step 2: Eliminate Technically Infeasible Options
LNBs with OFA Upgrades: TriState contracted with ACT to modify the existing Craig 3 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 Unit 3. 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 Unit 3.

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 Unit 3. 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[9]. 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: TriState received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 3 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 3 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 Unit 3.

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. 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 Unit 3. Tri-State conducted a site-specific SNCR study

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

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, a retrofit SCR system, the 0.07 lb/MMBtu controlled NO_x value is more expected, although Tri-State asserts that the unit 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 Unit 3.

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[10] 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 overfire air. Rich reagent injection was developed for cyclone boilers[11] 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 Unit 3 is equipped with low-NO_x burners with over-fire air (LNB+OFA) as part of a construction permit modification.**

Table 1 illustrates that this system achieves about 39% NO_x reductions (based on actual emissions) on Unit 3.

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[12]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

[10] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[11] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[12] 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

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,[13] 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 Unit 3 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_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: 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_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. 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 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. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers 15% to be a reasonable control effectiveness for SNCR.

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

SCR: Tri-State stated in the May 14, 2010 submittal the expected emission rate for Craig Unit 3 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[14]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).[15] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x emission reductions. Table 15 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

Table 15: 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 3	0.283	71.8	75.2	0.080	0.070

Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: Craig Unit 3 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Ultra-Low NO_x Burner (ULNB) Upgrade/Refinements	0 – 2% (TriState)	Y
Neural network system	0 – 5% (TriState)	Y
SNCR	10 – 40%	Y
Rotating overfire 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

[14] 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.

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

Step 4: Evaluate Impacts and Document Results

Factor 1: 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 overfire 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.[16] 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.

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.[17] 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.[18] The Tri-State-estimated SNCR costs for operating expenses are 70% for Craig Unit 3. 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.[19]

[16] 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.
[17] 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."
[18] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[19] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The cost effectiveness for SNCR on Unit 3 (at 15% control efficiency) is approximately $4,887 per ton. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (comparable to Unit 3) 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.[20,21] 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.[22] 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 inquired about the reagent and auxiliary power costs; Tri-State responded on July 30, 2010 adjusted the auxiliary power and lost generation costs for all of the Craig Units for both SNCR and SCR. Tri-State also provided further information regarding the cost of potential reagent options. The costs for these two items remain higher than other Colorado facility estimates; however, Tri-State has provided adequate information detailing the reasoning for power and reagent costs. The Division and Tri-State still do not completely concur on other cost items, including an annual 3% escalation rate for capital material, capital labor, capital indirect, and operation and maintenance. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division will use Tri-State's capital and operation/maintenance costs for this analysis in the absence of additional information at this time.

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.[23,24 25,26] 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 17 and Table 18 depict controlled NO_x emissions and control cost comparisons.

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[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.

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

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

[24] 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.

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

[26] 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 17: Craig Unit 3 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	---	5,693	0.283	
Combustion control refinements	2	5,579	0.277	0.32
Neural network system	5	5,408	0.268	0.31
SNCR	15	4,839	0.240	0.28
SCR	75	1,412	0.070	0.08

Table 18: Craig Unit 3 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	114	$122,000	$1,071	$1,071
Neural network system	285	$280,000	$984	$925
SNCR	854	$4,173,000	$4,887	$4,887
SCR	4,281	$239,762,387	$6,952	$7,466

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: 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.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, 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 (optional): 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 19 shows the number of days pre- and post-control. Table 20 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Table 19: 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 2nd	3	0.365	Mt. Zirkel Wilderness	239	---	---	173	---	---

half 2009 NOx rate									
2009 New LNBs	3	0.283		239	234	5	173	170	3
SNCR	3	0.240		239	233	6	173	166	7
SCR	3	0.070		239	224	15	173	149	24

Table 20: 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
			(dv)	(Δ dv)	(%)
Max 24-hour 2nd half 2009 NOx rate	3	0.365	5.20	---	---
2009 New LNBs	3	0.283	4.99	0.21	4%
SNCR	3	0.240	4.88	0.32	6%
SCR	3	0.070	4.41	0.79	15%

Step 6: Select RP Control

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Craig Unit 3 is SNCR control at the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)

For SNCR at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

- Unit 3: $4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve this RP emission limit shall be installed, maintained, and operated in a manner consistent with good air pollution control practice for minimizing emissions. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze State Implementation Plan.

V. Reasonable Progress Evaluation of Ash Hauling & Storage (P204) and Limestone Hauling (P201)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 96OPMF155.

Ash hauling (P204) is controlled with two methods to minimize fugitive emissions:

- Ash deposited in trucks for transport to disposal areas shall be sufficiently moist (Condition 8.2).
- The scrubber sludge/ash haul road servings Units 1, 2, and 3 shall be treated with magnesium chloride or equivalent as a dust suppressant. The magnesium chloride shall be applied according to manufacturer's specifications. The frequency of application shall be according to manufacturer's recommendations (Condition 8.3).

Limestone hauling (P201) activities are controlled several ways to minimize fugitive emissions:

- Opacity limitations of 20% except under certain operational conditions (U.S. EPA Reference Method 9) (Conditions 6.2, 11.2, and 11.3)
- Unloading facilities are vented to a baghouse (Condition 6.3)
- All process equipment shall be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their in the pollution control system (Condition 6.4)

These existing controls and corresponding emission limits in Section II, Conditions 6 and 8 of Operating Permit 96OPMF155 represent the most stringent level of control available for these fugitive dust sources.

Therefore, the Division proposes that RP for these sources is no additional control and the current emission limit for the above units is RP.

VI. Reasonable Progress Evaluation of Units 1 & 2

Units 1 and 2 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Units 1 and 2 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available NO_x, SO_2, and PM/PM_{10} control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO_2, or PM/PM_{10} for Units 1 and 2 at Craig Station.