Best Available Retrofit Technology (BART) Analysis of Control Options For Public Service Company – Comanche Station, Units 1 and 2

I. Source Description

Owner/Operator:	Public Service Company
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	Unit 1: 10100226 Unit 2: 10100222
Boiler Type:	Three Dry-Bottom Pulverized Coal-Fired Boilers, two tangentially fired (Units 1 and 3) and one wall-fired (Unit 2)

Comanche Station is located at 2005 Lime Road in Pueblo, CO, which is located within Pueblo County. Comanche Station commenced operation in the early 1970s. The facility originally consisted of two coal fired boilers, driving steam turbines used to generate electricity and associated support equipment (cooling and service water towers and coal and ash handling equipment). Unit 1 commenced operation in 1972 and serves a generator rated at 325 MW. Unit 2 commenced operation in 1975 and serves a generator rated at 335 MW. The boilers burn sub-bituminous coal from the Powder River Basin (PRB) as fuel and use natural gas for startup, shutdown and flame stabilization.

In August of 2004, Public Service Company of Colorado (PSCo) proposed to construct and operate a new coal-fired boiler (Unit 3) at Comanche Station. As part of that project, PSCo proposed to install control devices on the existing units. PSCo entered into a Settlement Agreement in December 2004 with various citizen groups and voluntarily agreed to install additional control devices and take emission limitations. In addition to the new unit (Unit 3), additional support equipment was proposed including a cooling tower, coal and ash handling equipment and various support equipment for the control device reagents (e.g., silos for lime, recycle ash and sorbent). Construction permits for the project were issued on July 5, 2005.

Low NO_X burners with over-fire air and a lime spray dryer were installed in November 2008 on Unit 1 and low NO_X burners with over-fire air and a lime spray dryer were installed in November 2007 on Unit 2. Operation of the SO_2 controls did not commence until June 3, 2009 for Unit 1 and January 10, 2009 for Unit 2. Unit 3 commenced operation in January 2010.

Units 1 and 2 are considered BART-eligible because the units were in existence on August 7, 1977 and not in operation prior to August 7, 1962 and are located at a fossil-fuel-fired steam electric plant greater than 250 MMBtu/hr, with the potential to emit of more than 250 tons or more of any visibility impairing air pollutant (NO_X, SO_2, PM_{10}). The results of the initial BART modeling analysis, indicated that the visibility impairment exceeded 0.5 deciviews (98% percentile -

8th high), at federal Class I areas. Therefore, since Units 1and 2 "cause or contribute" to visibility impairment BART applies to these units.

Table 1 below lists the units at Public Service Company Comanche Station that are subject to BART and are addressed in this BART analysis as well as the control efficiency of the controls currently installed on Units 1 and 2 (note SO_2 and NO_X controls were installed within the baseline period).

Table 1: Comanche Units 1 and 2 Technical Information

	Unit 1	Unit 2
Placed in Service	December 1973	November 1975
Boiler Rating, MMBtu/Hr for coal	3,531	3.482
Electrical Power Rating, Gross Megawatts	325	335
Description	Combustion Engineering Tangentially Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization.	Babcock and Wilcox Wall-Fired Dry Bottom Boiler. Coal-Fired with Natural Gas Used for Startup, Shutdown and/or Flame Stabilization.
Air Pollution Control Equipment	PM/PM_{10} – Baghouse – Installed 1993 NO_X – Low NO_X Burners with Over-Fire Air – Installed November 2008 SO_2 – Lime Spray Dryer – Installed November 2008, fully operational 6/3/09	PM/PM_{10} –Baghouse – Installed 1991 NO_X – Low NO_X Burners with Over-Fire Air - Installed November 2007 SO_2 – Lime Spray Dryer – Installed November 2007, fully operational 1/10/09
Emissions Reduction (%)*	NO_X – 62.7% SO_2 – 76.1% PM – 99.7% PM_{10} – 99.0%	NO_X – 44.1% SO_2 – 81.9% PM – 99.8% PM_{10} – 99.3%

*Emissions Reduction estimated by comparing pre-control 2005 – 2007 CAMD data (2005 – 2006 for NO_x on Unit 2) to controlled 2009 data. For PM/PM_{10}., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Comanche APCD Technical Analysis" for further details. Not based on actual testing.

PSCo submitted a BART analysis to the Division on August 1, 2006, with revisions to that analysis submitted on August 15, 2006 (editorial corrections), October 19, 2006 and January 8, 2007. At the Division's request, PSCo submitted additional information dated January 19, February 24, March 1, April 12, April 21, May 25, July 14, and July 22, 2010. These documents are included as "PSCo BART Submittals".

II. Source Emissions

In PSCO's August 1, 2006 BART application, baseline emissions were based on calendar year 2004 and 2005 emissions. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Additionally, PSCo, as detailed in Table 1, has installed air pollution controls on both units at Comanche in 2008. Therefore, the Division used years 2009 (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.

Controls were installed on Unit 2 in November 2007 and controls were installed on Unit 1 in November 2008. While the SO_2 controls did not commence full operation until 2009, the NO_X controls did commence operation upon installation. In addition, PSCo has indicated that lime was initially injected into the lime spray dryers in December 2008 for Unit 1 and July 2008 for Unit 2 in order to test the controls. The baseline emissions are summarized in Table 2.

Table 2: PSCo Comanche Units 1 & 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO_x	1,511	0.124	2,349	0.165
SO_2	1,557	0.128	1,244	0.091
PM_{10}	80	0.007***	40	0.005***

*Using daily CEMs data from 2009 calendar year (CAMD data).
**The Division calculated average emission rate or used the CAMD reported rate (lb/MMBtu) from the 2009 calendar year (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 (March 2003).

III. Units Evaluated for Control

According to PSCo's August 1, 2006 BART application sub-bituminous coal from the Powder River Basin (PRB), Belle Ayr mine in Wyoming is typically used as fuel. The characteristics of the Belle Ayr PRB coal presented in the August 1, 2006 BART application are presented below in Table 3.

Table 3: Comanche Station Coal Specifications (From August 1, 2006 BART Application)

Coal Mine/Region	PRB – Belle Ayr
Coal Rank Classification	Sub-bituminous
Proximate Analysis	
H_2O (Moisture weight %)	29.9
Ash (weight %)	4.6
Sulfur (weight %)	0.31
Ultimate Analysis	
Nitrogen (weight percent %)	0.68
Other	
Heating Value (HHV Btu/lb)	8,550

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 Comanche BART-eligible sources[1]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	8.4	9.5	46.6	10.7
Unit 2	7.4	9.5	46.6	10.7

*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 (2006-2009). Please refer to "Comanche APCD Technical Analysis" for more details.

Emission limitations that apply to these boilers are as follows:

- Colorado Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu, for each boiler.
- Colorado Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu, for each boiler.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits NO_X emissions to 0.40 lb/MMBtu and 0.46 lb/MMBtu, both on an annual average basis for Units 1 and 2, respectively.
- 40 CFR Part 60 Subpart D §§ 60.44(a)(3) and 60.45(g)(3), as adopted by reference in Colorado Regulation No. 6, Part A limits NO_X emissions to 0.7 lb/mmBtu, on a 3-hr rolling average. Applies to Unit 2 only.
- Colorado Construction Permits 11PB859, IA, mod 1 (Unit 2) and 04PB1429, IA (Unit 1) both issued July 5, 2005)
  - NO_X emissions shall not exceed 0.20 lb/MMBtu, on a 30-day rolling average, for each unit.
  - SO_2 emissions shall not exceed 0.12 lb/MMBtu, on a 30-day rolling average, for each unit.

  These limits shall be met no later than 180 days after the initial startup of the SO_2 and NO_X control equipment for each unit or by July 1, 2009, whichever is earlier
  - NO_X emissions from both Units 1 and 2 together shall not exceed 0.15 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)
  - SO_2 emissions from both Units 1 and 2 together shall not exceed 0.10 lb/MMBtu, on an annual rolling average basis (rolling on a daily basis)

  PSCo shall begin calculating compliance with these limits no later than 180 days after initial startup of the SO_2 and NO_X control equipment for the last unit.
  - Filterable PM emissions shall not exceed the following limits: Unit 1: 393 tons/quarter and 1,546 tons/yr and Unit 2: 390 tons/quarter and 1,525 tons/yr.

[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

- Filterable PM_{10} emissions shall not exceed the following limits: Unit 1: 363 tons/quarter and 1,423 tons/yr and Unit 2: 357 tons/quarter and 1,403 tons/yr.
- SO_2 emissions from Units 1 and 2 together shall not exceed 939.3 tons/quarter and 3,686 tons/yr.
- NO_X emissions from Units 1 and 2 together shall not exceed 1,564.4 tons/quarter and 6,142 tons/yr.

The above limitations take effect 180 days after initial startup of the last control device for the last unit or upon startup of Unit 3, whichever is earlier. Note that the quarterly limits apply for the first year of operation only.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

Semi-Dry 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 semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Comanche Units 1 and 2 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 Construction Permit limits are depicted in Table 5.

Table 5: Comanche Units 1 & 2 SO_2 Operating Permit Limits

	SO_2 limits (lb/MMBtu)	
	30-day rolling	Annual rolling (combined)
Units 1 & 2	0.12	0.10

As indicated in EPA's BART Guidelines [70 FR 39171], for dry-FGD (i.e., LSDs) the following scrubber upgrades should be considered.

- Use of performance additives

[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.

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

In addition to upgrades to the scrubbers, the Division also asked PSCo to look into the feasibility of achieving a lower 30-day SO_2 emission limitation with the existing controls (i.e., SO_2 emission limit tightening) and/or other potential upgrades, including improved operations and maintenance, use of more reagent, and keeping more spare parts on hand.

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an SO_2 upgrade analysis to the Division on May 25, 2010 and additional information on July 22, 2010 regarding potential upgrades for the LSDs installed on Comanche Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

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.

Dry FGD Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[3]. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

As indicated previously, as part of a permitting action to construct and operate a new unit (Unit 3) at Comanche Station, PSCo committed to installing both NO_X and SO_2 controls on Units 1 and 2. Permits were issued on July 5, 2005 for Units 1 and 2 which addressed the controls and the associated emission limitations that these units would be required to meet prior to commencing operation of the proposed new unit. To that end, a lime spray dryer (LSD) was installed on Unit 1 in November 2008 and a LSD was installed on Unit 2 in November 2007. Full operation of the LSDs commenced in June 2009 and January 2009 for Units 1 and 2, respectively. Table 1indicates that the LSDs are achieving

[3] 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.

emission reductions at approximately 76% for Unit 1 and 82% for Unit 2 in comparison with the permit limits[4] depicted in Table 5. It should be noted that since July 1, 2009, when the SO_2 limits became applicable, Unit 1is achieving emission reductions at about 86.5% and Unit 2 at 85.3%. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits. Therefore, since Comanche Units 1 and 2 are equipped with existing FGD and are achieving removal efficiencies greater than 50%, the BART analysis need not consider replacement of the SO_2 controls but should consider upgrades to the existing FGD.

-*Use of performance additives:* The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous SO_2. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same SO_2 reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in SO_2 removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the SO_2 removal. Therefore, this upgrade is not technically feasible. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase SO_2 removal and therefore warrants no further consideration.

-*Use of more reactive sorbent:* All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve SO_2 removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO_2. Since NO_2 is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO_2 removal rates, such as those experienced at Hayden.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove SO_2. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied

[4] Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

by Rockwell and used rotary atomizers. The unit was designed to obtain 70% SO_2 removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO_2 due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher SO2 removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes SO_2 removal; there are no known acceptable reagents without side effects that would allow additional SO_2 removal in the dry scrubbing systems present at Comanche Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

Increase the pulverization level of sorbent: PSCo indicated that Colorado's dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. Although PSCo notes that there have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. Their experience has been that there is no SO_2 removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. PSCo considers that they already uses the best available grinding technologies and that there are no improvements that can be done to further decrease lime particle size to reduce SO_2 emissions. The Division agrees that upgrades to grinding technologies are unlikely to produce additional SO_2 reductions and therefore no further consideration is warranted.

Engineering redesign of atomizer or slurry injection system: The Comanche dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both SO_2 removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO_2 removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved SO_2 removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO_2 removal level, although some have improved wear life and reduced maintenance costs. Given that the LSDs installed on Units 1 and 2 were installed recently, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher SO_2 removal.

Emission limit tightening: In addition to considering upgrades to the existing FGDs on Units 1 and 2, the Division asked PSCo to consider whether tightening of the existing BART 30-day limits was feasible. Comanche Units 1 and 2 are subject to the following SO_2 emission limitations:

Table 6: Comanche Units 1 & 2 SO_2 Emission Limitations

	SO2 Emission Limitations				
	Emission Rate (lb/MMBtu)			Mass Emissions (tons)	
	3-hr rolling	30-day rolling*	365-day rolling	Quarterly	Annual
Unit 1	1.2	0.12	N/A	N/A	N/A
Unit 2	1.2	0.12	N/A	N/A	N/A
Units 1 and 2 Together	N/A	N/A	0.10	939	3.686

*Included as limits in the BART construction permit (07PB0112B) issued September 12, 2008.

In their May 25, 2010 submittal, PSCo addressed the feasibility of tightening their 30-day SO_2 emission limits. In their submittal, PSCo indicated that based on operating experience for Comanche Units 1 and 2, as well as other PSCo units equipped with LSDs, that the primary factor affecting the SO_2 control efficiency for short-term averages are startups, equipment malfunctions and low load operations. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below the minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. PSCo indicated that this had actually occurred while operating Comanche Unit 2 and Valmont Unit 5 and resulted in extended maintenance outages in order to clean the scrubbers. In addition, during unit start-ups, it can take anywhere from between 12 and 24 hours to get the inlet scrubber temperature up to the level necessary for safe slurry injection. The scrubber can be run at higher levels of SO_2 reduction in order to offset the effects of a startup during a 30-day period, but the more startups that occur during that 30 day permit the more difficult it will become to offset the higher emissions during startup. PSCo also indicated that during low load operations, especially in the winter, the inlet temperature at the baghouse approaches the minimum acceptable level, subsequently lowering the overall SO_2 control efficiency during low load operations. PSCo indicated that due to the increased use of wind resources, the boilers will be required to cycle more frequently to accommodate intermittent wind resources and therefore, the units will run at low loads more frequently and as a result the SO_2 reduction levels will be lower during those times.

The Division reviewed available SO_2 emission data from CAMD for 2009 and for part of 2010 (January – October 2010). As previously indicated although the LSDs were installed in 2007 and 2008, they only recently commenced full operation, Unit 1 in June 2009 and Unit 2 in January 2009. As a result there is limited data available to determine post-control achievable emissions. In addition, if as PSCo indicates, the units are cycled more frequently to accommodate increased wind energy resources, it is not clear how well the data represents future operation. In addition, since the LSDs came on line recently, PSCo has limited operating experience with these units. Although PSCo has other units that are equipped with LSDs and have been operating those units with LSDs for some time (e.g., Valmont Unit 5, Hayden Units 1 and 2), those units are not using PRB coal. Comanche Units 1 and 2 represent the first units in PSCo's system with LSDs that are firing PRB coal as fuel. After startup of the LSDs in 2009 both units have had a number of days indicating zero emissions, presumably due to a unit shutdown. In addition, in many cases, emissions data shows that frequently for one or more days following these events, the daily SO_2 emission rate is well above 0.12 lb/MMBtu. Unit 1 averaged 0.07 lb/MMBtu during this period, with a maximum rate of 0.10 lb/MMBtu in December 2009. Unit 2 has had several months (December 2009, May 2010, October 2010) during the 2009 – 2010 timeframe that either exceed or are within 0.01 lb/MMBtu of the existing 0.12 lb/MMBtu 30-day rolling average limit. A review of annual data showed that in 2009, the SO_2 annual average from both units was approximately 0.11 lb/MMBtu. In 2010 thus far, the annual average is 0.07 lb/MMBtu, but it is important to note that it is apparent from the data on both units historically that lower inlet temperature(s) to the scrubber(s) in the winter months result in increased SO_2 emissions.

As explained above, the Division projects 30-day rolling SO_2 emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer or greater to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy. Therefore, the Division concurs that tighter 30-day rolling average and annual average SO_2 emission limit is not feasible at this time for either unit.

Additional equipment and maintenance: As discussed in the emission limit tightening section, PSCo reviewed actual operating experience on Comanche along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect SO_2 control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, SO_2 emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control SO_2 by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum acceptable levels, thus lowering overall SO_2 control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

PSCo sent confirmation to the Division on July 22, 2010 that an extra scrubber module on Comanche Units 1 and 2 is not feasible due to the current layout of the ductwork and space constraints around the scrubbers. The Division concurs with this assessment. Therefore, since it is not technically feasible to install an extra scrubber module, additional spare atomizer parts and increased operating and maintenance will not result in decreased SO_2 emissions. The Division concludes that this option is not technically feasible for Comanche Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased SO_2 reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct a control effectiveness evaluation.

Step 4: Evaluate Impacts and Document Results

PSCo indicated and the Division concurred that upgrades to the LSDs installed on Comanche Units 1 and 2 were unlikely to result in increased SO_2 reductions and therefore, would not be considered further. Therefore, there are no remaining technologies for which to conduct an evaluation of the cost, energy and non-air environmental impacts, and remaining useful life.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various potential emission rates. 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 6 shows the number of days pre- and post-control. Table 7 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[5], 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-

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

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 Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu.

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.

Table 6: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Unit(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 2	0.75 0.74	Great Sand Dunes National Park	60	---	---	27	---	---
Dry FGD	1	0.12		60	49	11	27	21	6
	2			60	50	10	27	21	6
Dry FGD	1	0.10		60	48	12	27	21	6
	2			60	49	11	27	21	6
Dry FGD	1	0.08*		n/a					
	2			n/a					
Dry FGD	1	0.07		60	48	12	27	20	7
	2			60	48	12	27	21	6
Combo	1 2	0.12		60	4	56	27	1	26

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Table 7: Visibility Results – SO_2 Emission Rates

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 2	0.75 0.74	2.05	---	---
Dry FGD	1	0.12	1.71	0.35	17%
	2		1.72	0.33	16%
Dry FGD	1	0.10	1.69	0.36	17%
	2		1.71	0.35	17%
Dry FGD	1	0.08*	1.68	0.37	18%

	2		1.69	0.36	18%
Dry FGD	1	0.07	1.67	0.38	18%
	2		1.69	0.37	18%
Combo	1 2	0.12	0.36	1.69	82%

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART is the following existing SO_2 emission rates:

Comanche Unit 1: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

Comanche Unit 2: 0.12 lb/MMBtu (30-day rolling average)
0.10 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). A 30-day rolling SO_2 limit of 0.12 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

B. Filterable Particulate Matter (PM_{10})

Comanche Units 1 and 2 are each equipped with fabric filter baghouses to control PM/PM_{10} emissions. In a baghouse, the particle laden flue gas passes through a series of fabric bags. The bags accumulate a filter cake that removes the particles from the flue gas, and the cleaned flue gas passes out of the fabric filter. The filter cake increases both the filtration efficiency of the cloth and its resistance to gas flow. The bags are periodically cleaned when too much filter cake builds up and increases the pressure drop across the fabric filter. A baghouse is considered the best particulate matter control device particularly for boilers burning low sulfur western coals.

As indicated previously in Table 1, estimated control efficiencies for the baghouse are over 99% for both PM PM_{10}. These control efficiencies are based on the allowable post-control emissions rate of 0.1 lb/MMBtu for PM and 0.092 lb/MMBtu for PM_{10} (assumes PM_{10} = 92% of PM). Actual performance test data shown in Table 8 indicates that PM emissions from Comanche Units 1 and 2 are well below the allowable levels. The results of performance tests conducted in 2003 indicate the following emission rates:

Table 8: Comanche Units 1 and 2 Stack Test Results (2003)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}*	0.003	0.003
PM_{10} Control efficiency	99.6%	99.6%

*PM_{10} = 0.92 x PM

The BART construction permit (07PB0112B) issued on September 12, 2008 for Comanche Units 1 and 2 set a PM emission limitation of 0.03 lb/MMBtu, which is more stringent than the limit of 0.1 lb/MMBtu that currently applies to these units. Although test results indicate that emissions below the 0.03 lb/MMBtu BART limit are certainly achievable, the 2003 performance test is just one 3-hour test and does not necessarily represent achievable emission rates over all operating conditions. Therefore, the Division considers that the PM limit set the BART permit is still appropriate. Using the allowable post-control PM BART limit of 0.03 lb/MMBtu BART limit, the control efficiency of the baghouses are indicated in Table 8 above.

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. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details.

Based on recent BACT determinations, the state has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent level of available control for $PM/PM_{10.}$ The units are exceeding a PM control efficiency of 95%, and the state has selected this emission limit for PM/PM_{10} as BART. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for Comanche Units 1 and 2.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

In various submittals with respect to installing additional NO_X controls on Comanche Units 1 and 2, PSCo looked at two options:

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

As part of this BART evaluation, the Division identified and examined the following additional control options for these units:

- Powerspan Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Rotating Opposed Fired Air (ROFA), ROFA with SNCR
- Low NO_X Burners (LNB) with Separated Overfire Air (SOFA)
- Reburning
- Emission limit tightening

Since low NO_X burners with over-fire air (LNB-OFA) were recently installed on Units 1 and 2 (November 2008 for Unit 1 and November 2007 for Unit 2), the Division considers that further upgrades to the LNB-OFA would provide little in the way of additional reductions and therefore upgrades to the existing LNB-OFA were not considered.

Step 2: Eliminate Technically Infeasible Options

Selective non-catalytic reduction (SNCR): The SNCR process is based on a gas-phase homogeneous reaction, within a specified temperature range, between NO_X in the flue gas and either injected ammonia or urea to produce gaseous nitrogen and water vapor. SNCR systems do not employ a catalyst; the NO_X reduction reactions are driven by the thermal decomposition of ammonia and the subsequent reduction of NO_X. Consequently, the SNCR process operates at higher temperatures than the SCR process. Critical to the successful reduction of NO_X with SNCR is the temperature of the flue gas at the point where the reagent is injected. The necessary temperature range is 1,600 - 2,100°F. SNCR can typically achieve NO_X reductions on the order of 40-70%.

PSCo has indicated that SNCR is feasible for Unit 1. According to their April 6, 2009 submittal, PSCo conducted testing in the fall of 2008 on Unit 2 using a temporary SNCR system. The testing was done following the installation of LNB-OFA to determine if additional reductions could be achieved. Testing was conducted primarily at full load over a seven-day period using a single-level urea based-SNCR system. The SNCR system is sensitive to temperature and average exhaust temperature in the injection area for Unit 2 was nearly 2,200 ºF, which exceeds the optimal temperature for the technology. During the test periods, NO_X reductions were less than 10%, and in some cases during testing, an actual increase in NO_X emissions was seen. Therefore, PSCo considers that SNCR is not feasible on Unit 2 and the Division concurs.

Selective Catalytic Reduction (SCR): SCR systems are the most widely used post-combustion NO_X control technology on pulverized coal-fired boilers. The SCR process is an add-on control which uses a catalyst bed and ammonia injection for removal of NO_X emissions. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction. SCR systems can achieve NO_X reductions in the range of 60 – 90%. SCR is technically feasible for Comanche Units 1 and 2.

Powerspan Electro-Catalytic Oxidation (ECO)®: The Powerspan electrostatic oxidation process (ECO)® is an integrated air pollution control process that achieve reductions in multiple pollutants from coal-fired power plants, included NO_X, SO_2, mercury and fine particulate matter (particulate matter less than 2.5 microns). The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse and consists of an ECO reactor (to oxidize pollutants), absorber vessel (saturates and cools the flue gas, removes SO_2, NO_2 and oxidized mercury) and a wet electrostatic precipitator (removes acid aerosols, air toxics and fine particulate matter). To date the ECO® system has been used on a slipstream (50 MW) from a 156 MW boiler equipped with an electrostatic precipitator and low NO_X burners[6]. While the technology may be considered commercially available, it has only been demonstrated on the portion of the exhaust of a smaller boiler. Therefore, the Division considers that this technology is not feasible.

Rich Reagent Injection (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. RRI is similar to SNCR but the reagent at the lower furnace at significantly higher temperatures (2400 – 3100ºF).[7] The RRI process was originally developed for coal-fired cyclone boilers and the Division is not aware that RRI has been utilized on other types of coal-fired boilers. Therefore, the Division considers that RRI is technically infeasible for Comanche Units 1 and 2.

Rotating Opposed Fire Air (ROFA) and ROFA with SNCR: With ROFA air in injected into the furnace first which breaks up the fireball and creates a swirling air flow to increase combustion. The swirling air results in better mixing of the fuel and air and distributes the temperature more evenly throughout the furnace, which improves combustion and reduces NO_X emissions. Typical NO_X reductions from ROFA alone range from 45 – 60 percent.[8] As indicated in Table 3, the estimated NO_X reductions for Units 1 and 2 with LNB-OFA are over 55% percent. Since ROFA is not expected to provide more NO_X reductions than the current controls on Units 1 and 2, further review of ROFA is not warranted.

That same ROFA system can be used to inject urea or ammonia into the furnace. However, since the NO_X reduction efficiency for the Comanche Unit 1 and 2 LNB-OFA systems are comparable to ROFA, combining ROFA and SNCR is not likely to result in NO_X reductions significantly above the level achieved by the Unit 1 existing LNB-OFA in conjunction with SNCR (note that SNCR is not feasible on Unit 2). Therefore, ROFA-SNCR will not be considered further.

Low NO_X Burners (LNB) with Separated Over Fire Air (SOFA): Over-fire air (OFA) is a combustion control technology where a portion of the total combustion air is diverted from the burners and injected later in the combustion process, typically above the combustion zone. There are specific OFA configurations that are typically associated with tangentially-fired boilers, close-coupled to the burner, separated from the burner and combination. The high end of the NO_X reduction ranges for the various OFA configurations for tangentially fired boilers are lower than the range for LNB-OFA on wall-fired units.[9] Since alternate OFA configurations will not result in significant NO_X reductions beyond LNB-OFA, they will not be considered further.

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[6] http://www.powerspan.com/FirstEnergy_ECO.aspx

[7] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

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

[9] Srivastava et. al, September 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association, volume 55, pg 1370.

Reburning: In reburning, a portion of the total heat input (up to 25%) is provided by injecting a secondary (reburning) fuel above the main combustion zone. Combustion of the reburning fuel results in hydrocarbon fragments, which react with a portion of incoming NO_X which form nitrogen containing compounds which are ultimately reduced to N_2. The fuel used for reburning need not be the primary fuel. Natural gas has frequently been used as reburning fuel, as there are more issues to consider with coal as the reburn fuel (e.g. particle size). In general reburning can achieve greater than 50% NO_X reduction, but many reburning demonstration projects are no longer operating.[10] Reburning can be used in conjunction with other NO_X control technologies, such as LNB-OFA, SCR and SNCR. Given that the control efficiency with reburning alone is similar to the NO_X reduction efficiency of Comanche Units 1and 2 with LNB-OFA (see Table 4), the Division considers that further evaluation of reburning is not warranted.

Emission limit tightening: The Division conducted technical analyses to determine whether the current NO_x emission limit(s) could be more stringent based on actual emissions after installation of the low NO_x burners with over-fire air (Unit 1 – December 2008 – Oct. 2010 and Unit 2 - December 2007 – October 2010). This option is technically feasible for both units.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals[11], determined that 30-day NO_x rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. To be conservative, the Division projected an annual average emission rate at 15% for Comanche to determine control efficiencies and annual reductions.

The Division considered that two additional NO_X reduction options warranted further consideration. Although some of the identified control technologies were not considered technically infeasible, they offered similar NO_X reduction levels that are already achieved with the LNB-OFA installed on Comanche Units 1 and 2. The two additional NO_X reduction technologies warranting further review are SCR and SNCR (Unit 1 only). \

SNCR: In their April 20, 2010 submittal, PSCo indicated that a NO_X emission rate of 0.10 lb/MMBtu was achievable on Unit 1. The Division calculated the control effectiveness based on the difference between the baseline (2009) and expected emission rate. This calculated control effectiveness for Comanche Unit 1 is 29.5%. This control effectiveness estimate is roughly equivalent to EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers.

SCR: In their April 20, 2010 submittal, PSCo indicated that a NO_X emission rate of 0.07 lb/MMBtu was achievable on both Units 1 and 2. Again, the Division calculated the control effectiveness based on the difference between the baseline (2009) and expected

[10] Srivastava et. al, pp 1371-1372.
[11] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

emission rate. This calculated control effectiveness for Comanche Unit 1 is 51% and for Comanche Unit 2 is 63%. These control efficiencies are lower than EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[12,13] However, the resultant emission rate of 0.07 lb/MMBtu is consistent with the rates cited in the AWMA study. PSCo and the Division recognize and concur that the lower initial emission rates of 0.124 and 0.165 lb/MMBtu for Units 1 and 2 respectively result in reduced SCR control efficiencies.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from current NO_x emissions. The Division found that the maximum 30-day rolling emission rate for Unit 1 from December 2008 – October 2010 was about 0.15 lb/MMBtu and the average 30-day rolling rate was around 0.13 lb/MMBtu. For Unit 2, from December 2007 to October 2010, the maximum 30-day rolling emission rate was about 0.17 lb/MMBtu and the average 30-day rolling rate was around 0.17 lb/MMBtu. As explained above, the Division projects 30-day rolling NO_x emission rates to be approximately 15% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 15% buffer to be applied in this case, especially due to the facts stated above, including uncertainty regarding load operations, cold-weather operating, start-up, and cycling for renewable energy.

The Division also found that for 2009, the annual average emission rate for both units was approximately 0.15 lb/MMBtu, and a review of January – October 2010 found that annual average emission rate thus far is about 0.16 lb/MMBtu. The existing annual limit of 0.15 lb/MMBtu for both units is an appropriate NO_x emission limit at this time. Therefore, appropriate NO_x emission limits assuming existing low NO_x burner with over-fire air technology for Units 1 and 2 are 0.20 lb/MMBtu on a 30-day rolling average for each unit and 0.15 lb/MMBtu annual average for both units. A re-evaluation of these emission limits will occur for the next regional haze planning period.
Table 9 summarizes each available technology and technical feasibility for NO_x control.

Table 9: Comanche Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
SNCR	20 – 50%	Y
SCR	50 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Low NO_x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed

[12] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

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

Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45 – 65%	N
Coal reburn+SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

SNCR and SCR: In their January 19, 2010 submittal, PSCo provided cost information associated with SNCR for Unit 1 and SCR for both Units 1 and 2. PSCo used EPA's Coal Utility Environmental Costs (CUECost) workbook model to estimate capital and ongoing operating and maintenance costs. The costs were then levelized at 2016/2017 dollars based on a 20-yr life to determine annual costs. The levelized costs were reported in 2016/2017 dollars on the assumption that SNCR would be installed by 2015 and SCR would be installed by 2016, with an additional year to optimize operation of the new control equipment. PSCo submitted the inputs and outputs from CUECost to the Division in a March 1, 2010 e-mail to the Division. The levelized cost methodology and results were provided in Xcel internal memos dated February, 24, 2010 (submitted to the Division via e-mail on March 1, 2010) and April 16, 2010 (submitted via e-mail to the Division on April 21, 2010). According to PSCo's April 20, 2010 submittal, the cost per ton for SNCR for Unit 1 was estimated to be $ 4,342/ton and the cost per ton for SCR was estimated to be $15,173/ton for Unit 1 and $9,558/ton for Unit 2.

Although the Division does not dispute the levelized annual costs for SNCR and SCR, the baseline emission rates used to determine the cost per ton for the incremental reduction are not appropriate. For Unit 1, PSCo presumed baseline emission rates of 0.12 lb/MMBtu for SNCR and 0.13 lb/MMBtu for SCR and for Unit 2 PSCo presumed a baseline emission rate of 0.18 lb/MMBtu. The Division has set a baseline period of 2009. The baseline emission rates are shown in Table 1.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilerswill be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[14] The PSCo-estimated SNCR costs for operating expenses is about 69% for Comanche Unit 1. 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.[15]

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

The Division-calculated cost effectiveness for SNCR on Unit 1 is $3,644 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 1) achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[16,17] It should be noted that PSCo is estimating resultant emission rates much lower than 0.30 lb/MMBtu for this boiler. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[18] PSCo's estimates are above this range. However, the Division concludes that PSCo's cost estimates for SNCR are reasonable due to the low input NO_x emission rate and degree of retrofit difficulty.

SCR: Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[19,20] In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 15.3% is just slightly higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.[21] PSCo's cost estimates are above the NESCAUM study ranges due to the lower control efficiencies explained earlier. The Division concludes that PSCo's cost estimates for SCR are reasonable due to low emission reductions and retrofit difficulties.

Table 10, Table 11, Table 12, and Table 13 depict controlled NO_x emissions and control cost comparisons. Refer to "Comanche APCD Technical Analysis" for more details.

Table 10: Comanche 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	---	1,511	0.124	

[16] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[17] 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.
[18] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[19] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[20] 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.
[21] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

SNCR*	29.5	1,065	0.087	0.100
SCR**	51	740	0.061	0.070

*Determined based on difference between baseline (2009) and PSCo's expected emission rates
**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 11: Comanche 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	---	2,349	0.165	
SCR**	63	869	0.061	0.070

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 12: Comanche Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SNCR	445.6	$1,624,100	$3,644	---
SCR	770.4	$12,265,014	$15,920	$32,762

Table 13: Comanche Unit 2NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SCR	1,480	$14,650,885	$9,900	---

Energy and Non-Air Quality Impacts

SNCR and 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. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, 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. 100 – 300 kW is enough energy to power about 10 homes for a year. These energy requirements are minimal and were confirmed by PSCo in the January 19, 2010 submittal.

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. PSCo noted that the retrofit installation of an SCR typically requires the installation of new, larger induced draft fans to over-come the additional pressure drop created by the SCR catalyst. In addition, although PSCo acknowledged that the energy requirements for SCR are more significant than SNCR they did not quantify these impacts since the increase in house power usage are included in the ongoing operating costs for each technology in the CUECost model.

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.

PSCo did identify the change in operating mode for the coal fired boilers as more wind energy is brought onto the PSCo system as a non-air quality impact that would affect any NO_X control technology. PSCo noted that typically coal-fired boilers are operated as base-loaded units and as such they typically run at full load 24-hours a day, with only minor load reductions at night when demand is lower or during off-peak periods in the spring and fall. However, with more wind resources replacing other conventional power sources, the load may be dropped further since demand for power is less. Therefore, the load on coal-fired units may be further reduced, particularly during peak wind generating periods. PSCo considers that operating these units at lower loads may affect the NO_X control technologies and result in lower NO_X reductions than those that would be seen at high loads.

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

In their January 19, 2010 submittal PSCo indicated that the remaining useful life of Comanche Units 1 and 2 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. 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 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98th 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 NO_x BART control technology on a given unit, emission rates for the other pollutants (SO_2 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 Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu.

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 14: 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 2	0.40 0.53	Great Sand Dunes National	60	---	---	27	---	---
NOx @	1	0.20		60	57	3	27	24	3

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

0.20 lb/MMBtu			Park						
NOx @ 0.20 lb/MMBtu	2	0.20		60	51	9	27	21	6
SNCR @ 0.10 lb/MMBtu	1	0.10		60	51	9	27	22	5
SNCR not feasible	2	n/a		60	n/a	n/a	27	n/a	n/a
SCR @ 0.07 lb/MMBtu	1	0.07		60	51	9	27	21	6
SCR @ 0.07 lb/MMBtu	2	0.07		60	47	13	27	18	9
Combo	1 2	0.07		60	4	56	27	1	26

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Table 15: 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 Impact Improvement from new LNB (2009)	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1 2	0.40 0.53	2.05	---	---	---	---
New LNB (2009)	1	0.20	1.90	0.16	n/a	8%	n/a
	2	0.20	1.75	0.31	n/a	15%	n/a
SNCR	1	0.10	1.79	0.26	0.11	13%	$6,175,284
SNCR not feasible	2	n/a					
SCR	1	0.07	1.76	0.30	0.14	14%	$41,576,317
	2	0.07	1.58	0.47	0.17	23%	$31,172,095
Combo	1 2	0.07	0.36	1.69	n/a	82%	n/a

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Comanche BART Modeling Summary" for more details.

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein , the state has determined that NO_x BART is following existing NO_x emission rates:

Comanche Unit 1: 0.20 lb/MMBtu (30-day rolling average)

	0.15 lb/MMBtu (combined annual average for units 1 & 2)
Comanche Unit 2:	0.20 lb/MMBtu (30-day rolling average)
	0.15 lb/MMBtu (combined annual average for units 1 & 2)

The state assumes that the BART emission limits can be achieved through the operation of existing low NO_x burners. Although the other alternatives achieve better emissions reductions, the added expense of achieving lower limits through different controls were determined based on the high cost/effectiveness ratios to not be reasonable coupled with the low visibility improvement (under 0.2 delta deciview) afforded.