Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Colorado Springs Utilities – Ray D. Nixon Power Plant

I. Source Description

Owner/Operator:	Colorado Springs Utilities
Source Types:	Electric Utility Steam Generating Unit
SCC (EGU):	10100222
Boiler Type:	Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas

The Nixon facility is located at 14020 Ray Nixon Road in Fountain, Colorado. This facility consists of one (1) steam driven turbine/generator unit, auxiliary boiler, the associated equipment needed for generating electricity, and two natural gas fired simple cycle combustion turbines driving electricity generators. The boiler fires low sulfur western coal as the primary fuel and can currently use No. 2 distillate oil or natural gas for an ignition fuel. The ignition fuels are used for startup of the boiler, flame stabilization, and the coal pulverizer startup. The facility also includes the various processes necessary to handle the coal, flyash and bottom ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control at appropriate point sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nixon power plant, 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.

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

[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.

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

Nixon Power Plant is considered a single source with six (6) other facilities, depicted in Table 1.

Table 1: Facilities Co-Located or Considered to be a Single Source with Nixon Power Plant

Emission Sources	Colorado Construction/Operating Permit #	Permit Holder
Coal Screen	98PO149	Western Resources
2 Anaerobic Digestors, 4 Biogas Boilers and 2 Flares	96OPEP152	CSU – Clear Spring Ranch Solids & Handling
2 Natural Gas Turbines	99EP0851	Front Range Power Company, LLC
1 Coal-fired Boiler, 2 Natural Gas Turbines, Cooling Tower, Ash Handling, Coal Handling, Auxiliary Boiler	95OPEP106	CSU – Nixon Power Plant
Wastewater Treatment and 3 Internal Combustion Engines	95EP1097	CSU – Las Vegas Street Municipal Treatment Plant
Custom Anaerobic Wastewater Treatment System	03EP0158	CSU – Northern Water Reclamation Facility

The two natural-gas fired combustion turbines at Front Range Power Plant (FRPP) are above the Prevention of Significant Deterioration significance level for NO_x. The other single source facilities emit NO_x, SO_2, and/or PM_{10} below the Prevention of Significant Deterioration significance levels.

The Front Range Power Plant (FRPP) is located at 6615 Generation Drive, Fountain, Colorado. The facility produces electrical power using two natural gas combustion turbines, with two Heat Recovery Steam Generators (HRSG), and duct burners. These two combustion turbines are evaluated within the source category "Combustion Turbines" in Section 8.2.3 of the Regional Haze SIP.

Nixon Unit 1 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. CSU provided information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 and additional relevant information on February 21, March 21, May 10, and June 2, 2010. Table 2 depicts technical information for Nixon Unit 1.

Table 2: Nixon/FRPP RP-eligible Emission Controls and Reduction (%)

	Nixon Unit 1
Placed in Service	April 1980
Boiler Rating, MMBtu/Hr for coal	2,049
Electrical Power Rating, Gross Megawatts	227
Description	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing coal. The coal burner ignitors fire No. 2 fuel or spec oil & NG
Air Pollution Control Equipment	Western Precipitation Thermoflex Fabric Filter (baghouse)
Special Features	Low NOx burners placed in service in 1989
Emissions Reduction (%)	NO_x – 37% SO_2 – None PM/PM_{10} – 99.9/99.7%

Regulations that apply to the boiler are as follows:
For Nixon Unit 1:

- NSPS Subpart D regulates particulate matter emissions to 0.1 lb/MMBtu.
- NSPS Subpart D regulates NO_X emissions to 0.7 lb/MMBtu.
- The Title V Operating Permit limits annual NO_X emissions to 2853.3 tons per year.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program regulates NO_X emissions to 0.50 lb/MMBtu of heat input on an annual average basis.
- NSPS Subpart D regulates SO_2 emissions to 1.2 lb/MMBtu.

II. Source Emissions

Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM actual emissions averaged over the 2006 – 2008 timeframe with data from EPA's CAMD database, Colorado's Air Pollutant Emission Notices submitted by the facility, and Colorado inspection reports as applicable. Table 4 summarizes the NO_x, SO_2, and PM actual emissions averaged over the 2006 – 2008 timeframe (baseline) for each RP-eligible unit.

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit - Nixon Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Boiler #1	SO_2 (tons)	3877.6	4043.1	4442.3	4121.0
	SO_2 (lb/MMBtu)	0.46	0.52	0.53	0.50
	NO_x (tons)	2390.1	2137.0	2542.9	2356.7
	NO_x (lb/MMBtu)	0.26	0.26	0.26	0.26

	PM_{10} (tons)	89.24	82.29	88.78	86.8
	PM_{10} (lb/MMBtu)	0.011	0.011	0.011	0.011
Auxiliary Boiler	*SO_2 (tons)*	*0*	*0*	*0*	*0.0*
	SO_2 (lb/MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.02*	*0.02*	*0.05*	*0.0*
	NO_x (lb/MMBtu)	*1.50*	*1.50*	*1.52*	*1.51*
	PM_{10} (tons)	*0*	*0*	*0*	*0.0*
	PM_{10} (lb/MMBtu)	*0.000*	*0.000*	*0.000*	*0.000*
Nixon Combustion Turbine 1	*SO_2 (tons)*	*0.01*	*0.01*	*0.01*	*0.0*
	SO_2 (lb/MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.81*	*0.61*	*0.76*	*0.7*
	NO_x (lb/MMBtu)	*0.04*	*0.04*	*0.04*	*0.04*
	PM_{10} (tons)	*0.23*	*0.19*	*0.25*	*0.2*
	PM_{10} (lb/MMBtu)	*0.011*	*0.012*	*0.012*	*0.012*
Nixon Combustion Turbine 2	*SO_2 (tons)*	*0.01*	*0.02*	*0.01*	*0.0*
	SO_2 (lb/MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.97*	*1.67*	*0.85*	*1.2*
	NO_x (lb/MMBtu)	*0.04*	*0.05*	*0.05*	*0.05*
	PM_{10} (tons)	*0.27*	*0.36*	*0.23*	*0.3*
	PM_{10} (lb/MMBtu)	*0.012*	*0.012*	*0.014*	*0.012*
Coal Reclaim Conveyor (003)	PM_{10} (tons)	25.97	25.97	21.85	24.60
Ash Handling/Disposal (006)	*PM_{10} (tons)*	*1.41*	*1.41*	*1.41*	*1.41*
Coal Handling (008)	PM_{10} (tons)	23.2	23.2	1.47	15.96
Ash Haul Roads & Disposal (009)	*PM_{10} (tons)*	*1.85*	*1.85*	*1.87*	*1.86*
Unit #1 Cooling Tower	*PM_{10} (tons)*	*0.8*	*0.8*	*0.75*	*0.78*
Four Digester Gas Boilers	*SO_2 (tons)*	*10.15*	*9.03*	*9.03*	*9.40*
	NO_x (tons)	*4.95*	*3.84*	*3.84*	*4.21*
	PM_{10} (tons)	*0.50*	*0.35*	*0.35*	*0.40*
2 Digester Gas Flares	*SO_2 (tons)*	*11.0*	*11.19*	*11.19*	*11.13*
	NO_x (tons)	*2.61*	*2.65*	*2.65*	*2.64*
	PM_{10} (tons)	*0.54*	*0.40*	*0.40*	*0.45*
Sludge Injection & Unpaved Roads	*PM_{10} (tons)*	*8.90*	*8.90*	*8.90*	*8.90*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages are estimated to be 5-15% higher than the annual average emission rate (i.e. the 30-day NO_x rolling average is likely about 0.58 lbs/MMBtu for Boiler 1).

Units *italicized* in Table 2 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

Table 4. Nixon Unit 1 Baseline Emissions

Pollutant	Nixon Unit 1	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO_x	2,357	0.258
SO_2	4,121	0.453
PM_{10}	87	0.002***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).

**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions and for PM_{10} emissions for the turbines.
***The PM_{10} emission rate is determined from the Title V permit compliance stack test. These values are as follows: Nixon Unit 1 – 0.0021 lb/MMBtu (4/15/2008)

III. Units Evaluated for Control

As documented by CSU, Nixon Unit 1 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2007 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Nixon Unit 1	8,752	0.22	4.99

Table 1 lists the units at Nixon that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for Nixon Unit 1

Emission Unit	Pollutant	Fuel
		Coal (sub-bituminous) (lb/ton)
Nixon Unit 1[2]	NO_x	7.2
	SO_2	35 x %S = 7.7*
	PM/PM_{10}	PM – 49.90** PM_{10} – 11.48

*%S = % of sulfur present in coal supply. For example, 35 x 0.22 = 7.7
**%A = % of ash present in coal supply. For example, 10 x 4.99 = 49.90

IV. Reasonable Progress Evaluation of Nixon Unit 1

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

CSU identified one SO_2 control option:
Flue gas desulfurization (FGD):
Lime spray dry absorber (SDA or dry FGD)

The Division identified two additional SO_2 control options:
Flue gas desulfurization (FGD):
Lime or limestone-based (wet FGD)
Dry sorbent injection – Trona (DSI)

[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

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: 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 smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO_2 Emissions: A Review of Technologies[4] evaluates various SO_2 control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

CSU's 2009 submittal states that a dry FGD (SDA) system is technically feasible. The Division concurs with this conclusion.

The Division notes that traditional wet FGD controls are possible at Nixon Unit 1 considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls at Nixon Unit 1.

It is worth noting that CSU is currently testing a new, innovative non-traditional wet scrubber control system at another facility that appears to be as effective, if not more effective, at controlling SO_2 emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system,

[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.

[4] 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.

called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4.

Although the technology being tested by CSU does not technically meet the definition of "available" as set forth in the BART (Regional Haze) rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber at Nixon Unit 1 if desired and applicable. This process will be required to meet the emission limits established for the LSD technology established in this RP determination. Regardless of the technology utilized, Nixon has to meet the LSD-based RP limits within 5 years of EPA approval of the Regional Haze SIP. CSU will test the NeuStream system at this facility until December 2011, and at that time, determine the control technology that will be used to comply with the specified SO_2 RP limit for Nixon Unit 1.

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the airheater are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CSU's preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

One major challenge of DSI systems is the possibility of converting the NO_x present in the flue gas from NO which is colorless to NO_2 which has a reddish-brown color. This conversion of NO to NO_2 can create a brown plume from the stack which could create

opacity compliance issues. Due to variability of boiler configurations, coal composition, NO_x to SO_2 ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO_2 removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% SO_2 removal at another facility. In practical application, a higher SO_2 removal rate may be possible, while it is also possible that a lower SO_2 removal rate may be necessary to limit the brown plume formation. This determination would require actual SO_2 removal real-time testing. Therefore, since CSU notes that DSI is technically feasible for a similar facility, the Division assumes this same technology is also then technically feasible for Nixon Unit 1.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for Unit 1 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO_2 determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. 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.

Dry FGD (LSD): Controlling SO_2 Emissions: A Review of Technologies[5] indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Nixon Power Plant, typically <0.5% as detailed in Table 5, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Therefore, dry FGD is evaluated at two control efficiencies level – 78% (0.010 lb/MMBtu annual average) and 82.3% (0.08 lb/MMBtu annual average) for comparison purposes.

DSI: Based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved to be 60% SO_2 removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

[5] 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.

Table 7 summarizes each available technology and technical feasibility for SO_2 control.

Table 7: Nixon Unit 1 SO_2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	95%	Y
Dry FGD (LSD)	75 – 85%	Y
DSI	60% (CSU)	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

Wet FGD: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers.

LSD/DSI: CSU submitted cost estimates for a LSD system on Unit 1 on February 20, 2009. CSU provided cost estimates for the DSI system evaluated on another similar Colorado unit (CSU Drake Unit 5) on May 10, 2010.

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in Table 8. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of CO_2 when measured on a per MW-h basis. These estimates are for another facility, Drake Units 6 and 7, but are assumed to be directly applicable to Nixon Unit 1 as well.

Table 8: LSD Energy Replacement Costs

Unit	Replacement capacity cost ($/kW-yr)	Differential energy cost ($/MW-h)
Drake 6/7	44	35

This information, including detailed capital and annual cost data, are provided as "CSU Drake BART Submittals" and "CSU Nixon RP Submittals". CSU originally generated costs using EPRI's FGD Cost model for Drake.[6] This model uses specific unit data to

[6] EPA's BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO2 removal equipment as of

calculate the cost of controlling emissions, and is considered to be accurate within ± 30%. When preparing cost estimates for Nixon, cost estimates were developed using the IECCOST program.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,[7] shown in Table 9.

Table 9: CSU-Drake SO_2 LSD Control Cost Comparison

Unit Capacity (MW)	EPA's Calculated Cost Effectiveness for MW Group ($/ton SO_2 Removed)	CSU Refined Cost Estimate ($/ton SO_2 Removed (Control System))	Cost Differential
Drake Unit 6 – 85 MW	$2,399	$2,579 - $2,981	+ 8% – 24%
Drake Unit 7 – 142 MW	$1,796	$2,140 - $2,694	+ 19% - 50%
Nixon Unit 1 – 225 MW	$1,282	$3,744 - $3,950	+ 192% - 208%

EPA's study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Unit 1 using various cost updates from the 2008 timeframe. Nixon has reflected the costs of retrofitting a facility that is moderately congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. The Division does not necessarily concur with these estimates, but will accept them for purposes of this RP analysis.

CSU only submitted DSI cost information for another facility, Drake Unit 5. The Division scaled this cost information for Units 1 in Table 10. Please see "Drake APCD Technical Analysis" and "Nixon APCD Technical Analysis" for more details.

the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

[7] EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART SO_2 Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

For dry FGD, CSU estimated a removal rate of 80% based on 2008 average data and a resulting emission rate at the BART presumptive limits of 0.10 lb/MMBtu. The Division adjusted this removal rate using the baseline SO_2 emissions from Table 4 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 78 - 82%that meets the BART presumptive limit for Nixon Unit 1. This range allows the Division to determine the most reasonable RP limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See "Nixon APCD Technical Analysis" for more details.

Table 10 illustrates resultant SO_2 emissions for each technically feasible control option. Table 11 shows the SO_2 control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 4. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average SO_2 emission rate is approximately 5% higher than the annual average emission rate.

Table 10: Nixon Unit 1 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Unit 1		
		(tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	4,121	0.453	
DSI	60	1,649	0.181	0.190
Dry FGD (LSD) @ 78% control	78	907	0.100	0.105
Dry FGD (LSD) @ 82.3% control	82.3	729	0.080	0.084

Table 11: Nixon Unit 1 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI	2,473	$4,938,692	$1,997	$1,997
Dry FGD (LSD) @ 78% control	3,215	$12,036,604	$3,744	$9,568
Dry FGD (LSD) @ 82.3% control	3,392	$13,399,590	$3,950	$7,691

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[8], 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 CSU 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

Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential on-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the Regional Haze program. The Division largely focused its RP SO_2 control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO_2 control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO_2 emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO_2 emission reduction benefits (tons of SO_2 reduced annually) and visibility improvement (deciview improvement at nearest Class I

[8]Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

area) when compared to LSD or the pilot NeuStream-S FGD scrubber when applied to the Nixon Unit 1 boiler.

Semi-dry FGD (LSD): CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water, as detailed in Table 12. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[9]

Table 12: LSD Water Requirements

Unit	Water required for LSD (gpm)	Water required for LSD (Mg/year)
Drake 6	68	35.7
Drake 7	100	53.0
Nixon 1 (scaled)	~160	~84.0

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: CSU documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash.

The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash at some plants,[10] which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality

[9] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[10] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880. http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon Unit 1 in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 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 13 shows the number of days pre- and post-control. Table 14 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, 30-day SO2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 5% for all SO2 emission rates to determine control efficiencies and annual reductions.

Table 13: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Unit(s)	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-hr SO_2 rates	1	RMNP	17	---	---	6	---	---
DSI @ 0.18 lb/MMBtu	1		17	6	11	6	1	5
LSD @ 0.10 lb/MMBtu	1		17	6	11	6	1	5
LSD @ 0.08 lb/MMBtu	1		17	6	11	6	1	5

Table 14: Visibility Results – SO2 Control Scenarios

SO2 Control Scenario	Unit(s)	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
		(deciviews)	(deciviews)	(%)	($/deciview)
Max 24-hr SO_2 rates	1	0.914			---
DSI @ 0.18 lb/MMBtu	1	0.48	0.44	48%	$11,249,869

LSD @ 0.10 lb/MMBtu	1	0.46*	0.46	50%	$26,454,076
LSD @ 0.070 lb/MMBtu	1	0.42	0.50	55%	$28,307,522

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

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP the following SO2 emission rate:

Nixon Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with semi-dry FGD (LSD). A lower emissions rate for Unit 1 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.04 delta deciview). Also, stringent retrofit emission limits below 0.10 lb/MMBtu have not been demonstrated in Colorado, and the state determines that a lower emission limit is not reasonable in this planning period.

The LSD control for Unit 1 provides 78% SO_2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 1: $3,744 per ton SO_2 removed; 0.46 deciview of improvement

An alternate control technology that achieves the emissions limits of 0.11 lb/MMBtu, 30-day rolling average, may also be employed.

b. Filterable Particulate Matter (PM) & Particulate Matter (PM_{10})

Nixon Unit 1 is equipped with a reverse-air fabric filter baghouse 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.

Colorado Operating Permit 95OPEP106 Condition 1.5.5 requires Unit 1 to conduct performance testing for PM_{10} annually. While the emission limit in Condition 1.5.1 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 15 shows the most recent stack test data (April 14, 2008). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 15: Nixon Unit 1 2008 Stack Test Results

Pollutant	Unit 1 (lb/MMBtu)
Filterable PM_{10}	0.0021
PM_{10} Control efficiency	99.5%

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 current stack test results above are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

The state determines that the existing Unit 1 regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control options. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limits are RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/PM_{10} is not needed for Nixon Unit 1.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

CSU identified four NO_x control options:

- Overfire air (OFA)
- Ultra-low NO_x burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low NO_x burners and SCR (ULNBs + SCR)

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

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Ultra-low NO_x burners and Over-fire air (ULNBs+OFA)
- Selective Non-Catalytic Reduction (SNCR)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[11]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater NO_x reduction for Unit 1. Since ROFA® technology would not be expected to

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

provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

OFA: Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low NO_x burners, such as those already present on Unit 1. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO_x are formed[12]. The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Unit 1.

ULNBs: Unit 1 has low NO_x burners installed, shown in Table 2. These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased NO_x emission reductions with these ultra-low NO_x burners. ULNBs are a technically feasible option for Unit 1.

ULNBs+OFA: Since ULNBs and OFA are each technically feasible options and would be installed separately for Unit 1, it stands to reason that ULNBs+OFA is a technically feasible options for Unit 1.

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.

[12] IEA Clean Coal Centre: Clean Coal Technologies – Air Stating for NO_x control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion?

While lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for CSU Nixon, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Unit 1 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Nixon Unit 1.

ULNBs/SCR layered: A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Nixon Unit 1.This scenario considers that less NO_x would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for Nixon Unit 1.

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[13] 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[14] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Nixon Unit 1.

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

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

a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's RP analysis because CSU asserts that SNCR achieves full-load NO_x removal in the same range as ULNB at a higher levelized cost ($/ton NO_x removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule, and therefore should be ruled out for RP as well. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal NO_x removal, resulting in NO_x removal declines. The weighted average NO_x removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a technically feasible alternative for Nixon Unit 1. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a NO_x control option for EGUs, so the Division included SNCR in the full four-factor analysis.

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

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[16] 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 Nixon Unit 1 to determine control efficiencies and annual reductions.

OFA: CSU estimated that overfire air, in conjunction with the existing low-NO_x burners, is capable of reducing NO_x emissions approximately an additional 25% from existing conditions in the original BART submittal (August 1, 2006). EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with

[15] 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
[16] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

OFA controlling 40 – 60% of NO_x emissions.[17] The low NO_x burners currently achieve about 10% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low NO_x burners.[18] Therefore, the Division concurs with CSU's additional 25% NO_x control estimate.

ULNBs: CSU asserts that additional NO_x reductions of 20% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at Nixon Unit 1. These additional NO_x reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled NO_x emissions, which is consistent with a U.S. Department of Energy Study which estimated NO_x emissions reductions between 75 – 85%.[19] Therefore, the Division concurs with CSU NO_x reduction estimates for ULNBs.

ULNBs+OFA: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. ULNBs alone can achieve 20% control; OFA alone can achieve 25% control. When determining the appropriate control efficiency regarding the combination of ULNBs and OFA, the most important consideration to note is that Nixon burns only Power River Basin (PRB) coal which is low in nitrogen content initially, so the margin to reduce NO_x is lower than other facilities (i.e. Drake). The Division and CSU concur that a realistic control efficiency assumption is 30% for Nixon Unit 1.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[20] to conservatively approximate that Nixon Unit 1 can achieve 30% control when SNCR is applied.

*SCR:*CSU approximates that SCR can achieve an approximate 80% NO_x reduction using 2008 baseline emissions (or 0.05 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions and adjusted the resultant SCR percent removal to 73% (or 0.07 lb/MMBtu), which the Division considers more realistic and consistent with other Colorado facility submittals. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80

[17] 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
[18] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[19] U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory. http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf
[20] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

– 90% reduction.[21,22] However, in the Division's experience a emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

ULNBs/SCR layered approach: CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce NO_x entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same NO_x emission reductions as SCR alone and is deemed to be appropriate by the Division.

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

Table 16: Nixon Unit 1 7 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	~10%	Y – installed
LNB + OFA	60 – 81%	Y (partially installed)
Overfire air (OFA)	10 – 25% (alone)	Y
Ultra-low NO_x burners (ULNBs)	20%	Y
ULNBs+OFA	30%	Y
Selective non-catalytic reduction (SNCR)	20 – 40%	Y
Selective catalytic reduction (SCR)	70 – 90%	Y
ULNB/SCR layered approach	70 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

OFA: Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake and Nixon boilers in 2004. The cost estimates were generated using EPRI's IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "NO_x

[21] 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

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

Controls for Existing Utility Boilers,"[23] OFA alone ranges from $410 - $1,100 per ton NO_x reduced annually for units estimating 15 – 30% NO_x control, which is within the range of Nixon's estimated OFA NO_x reductions (25%). The estimates in Table 17 and Table 18 are within this range. Therefore, the Division concurs with the OFA cost estimates.

ULNBs: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 18. The Division considers CSU's estimated costs more than reasonable, with ULNBs at about $1,200/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.[24, 25]
ULNB+OFA: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

SNCR: A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[26] A similar Colorado facility estimated operating expenses at approximately 81 – 86%.[27] 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.[28]

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[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. www.nescaum.org/documents/**nox**-2000.pdf
[25] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[26] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[27] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.
[28] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The Division used information from a similar facility submittal to determine approximate SNCR costs scaled for the Nixon boiler since CSU did not have SNCR information.[29] The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Nixon boiler in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 1 is approximately $4,500 per ton. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers 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.[30,31] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced. [32] Although the resulting cost estimates for the Nixon boiler greater than these ranges, the smaller size of the boiler as well as the difficulty of the retrofit leads the Division to the conclusion that the estimated cost estimates for SNCR are reasonable.

SCR: CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving NO_x emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing $2,600 - $7,400 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[33,34] The SCR system estimates for the CSU Nixon boiler is approximately $6,400, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

ULNBs/SCR layered approach: CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 17 illustrates resultant NO_x emissions for each technically feasible control option. Table 18 shows the NO_x control costs for each unit based on detailed cost analyses. The Division estimated resultant NO_x using annual average reductions for

[29] CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.
[30] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[31] 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.
[32] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[33] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[34] 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.

tons of NO_x reduced per year. The Division's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate.

Table 17: Unit 1 Control Resultant NOx Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Unit 1		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling (lb/MMBtu)
Baseline	---	2,357	0.258	
Ultra-low NOx burners (ULNBs)	20	1,885	0.206	0.24
Overfire air (OFA)	25	1,768	0.194	0.22
ULNBs+OFA	30	1,650	0.181	0.21
Selective Non-Catalytic Reduction (SNCR)	30	1,650	0.181	0.21
ULNB+SCR	73	636	0.070	0.080
Selective Catalytic Reduction (SCR)	73	636	0.070	0.080

Table 18: Unit 1 NOx Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Ultra-low NOx burners (ULNBs)	471	$567,000	$1,203	$1,203
Overfire air (OFA)	589	$403,000	$684	($1,392)
ULNBs+OFA	707	$907,000	$1,372	$4,812
Selective Non-Catalytic Reduction (SNCR)	707	$3,226,877	$4,564	---
ULNB+SCR	1,720.4	$11,007,000	$6,398	$7,677
Selective Catalytic Reduction (SCR)	1,720	$11,010,000	$6,400	---

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[35], the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and

[35] Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

shutdown, after SIP approval, it would take CSU be approximately 2-3 years for SNCR and 3-4 years for SCR. 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

OFA: Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ULNBs: The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. 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. 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 less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

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. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a aqueous ammonia reagent versus an ammonia reagent.

Factor 4: Remaining Useful Life

CSU asserts that the remaining useful life of Nixon 1 is in excess of 20 years, which is the maximum amortization period allowed in the RP analysis. Thus, this factor does not influence the selection of controls.

Factor 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 20depicts 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	Unit(s)	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 NOx rates	1	RMNP	17	---	---	6	---	---
ULNBs @ 0.21 lb/MMBtu	1		17	15	2	6	4	2
OFA @ 0.19 lb/MMBtu	1		17	15	2	6	4	2
ULNBs+OFA @ 0.18 lb/MMBtu	1		17	15	2	6	4	2
SNCR @ 0.18 lb/MMBtu	1		17	15	2	6	4	2
SCR @ 0.07 lb/MMBtu	1		17	12	5	6	3	3

Table 20: Visibility Results - NOx Control Scenarios

NOx Control Scenario	Unit(s)	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
		(deciviews)	(deciviews)	(%)	($/deciview)
Max 24-hour NOx rates	1	0.91	---	---	---
ULNBs @ 0.21 lb/MMBtu	1	0.77	0.15	16%	$3,831,081
OFA @ 0.19 lb/MMBtu	1	0.76*	0.15	17%	$2,616,883

ULNBs+OFA @ 0.18 lb/MMBtu	1	0.75*	0.16	18%	$6,024,845
SNCR @ 0.18 lb/MMBtu	1	0.75*	0.16	18%	$20,042,714
SCR @ 0.07 lb/MMBtu	1	0.68	0.24	26%	$46,639,831

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

Determination

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Nixon Unit 1 the following NOx emission rate:

Nixon Unit 1: 0.21 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved with ultra-low NOx burners with over fire air control. The Division notes that ultra-low NOx burners with over-fire air is the appropriate RP determination for Nixon Unit 1 due to the low cost effectiveness. SNCR would achieve similar emissions reductions at an added expense. Therefore, SNCR was determined to not be reasonable considering the low visibility improvement afforded.

V. RP Evaluation for Fugitive Dust Sources: Coal Reclaim Conveyor (003) and Coal Handling (008)

Both of these fugitive dust sources are permitted within Colorado Operating Permit 95OPEP106.

Coal handling is comprised of five (6) parts – reclaim tunnel bagfilter vent, coal crusher building bagfilter vent, coal gallery bagfilter vents, and coal train off-loading-conveying-stockpiling. It should be noted that while these two sources are reported individually in Colorado's emission inventory, in the Operating Permit, these sources are combined together since coal handling is treated as one point. Colorado Regulation No.1.II.A.1 limits opacity from these sources to 20%. This source is also subject to NSPS Subpart Y, New Source Performance Standards for Coal Preparation Plants. Additionally, the following measures to control fugitive dust via a fugitive particulate emissions control plan (Condition 3.4):

- A wet dust suppression system shall be used for railroad car unloading.
- Above ground conveyors to and from the transfer building must be covered.
- Loadout to storage must by telescoping chute.
- Emissions from coal storage piles shall be effectively controlled by application of chemical binders and by watering, if need be.

These existing controls and corresponding emission limits in Section II, Condition 3 of Operating Permit 95OPEP106 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.