Reasonable Progress (RP) Four-Factor Analysis of Control Options
For
Colorado Energy Nations, Golden, Colorado

I. Source Description

Owner/Operator:	Colorado Energy Nations (CENC) (formerly Trigen Colorado Energy Corporation)
Source Type:	Steam Generating Unit
Boiler Type(s):	Boiler 1 – Natural Gas Front-Fired (SCC: 10200601 for natural gas)
	Boiler 2 – Natural Gas Front-Fired (SCC: 10200601 for natural gas)
	Boiler 3 – Pulverized Coal Spreader Stoker (SCC: 10200224)
	Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)
	Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek and US Highway 58 borders the northern side of the CENC site.

Figure 1: CENC facility Aerial Perspective

The CENC facility consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operate in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/PM_{10} by separate fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the CENC facility, 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. Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and commenced operation in the 15-year period prior to August 7, 1977. Therefore, these two boilers have been evaluated for BART, which the Division has determined meets the requirements of RP at this time.

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

These levels are as follows:

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

Boiler 3 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. CENC submitted a "Reasonable Progress Control Evaluation" on May 7, 2010 as well as additional relevant information on February 8, 2010. Table 1 depicts technical information for Boiler 3 at the CENC facility.

Table 1: CENC Boiler 3 RP-eligible Emission Controls and Reduction (%)

	Unit B003
Placed in Service	1962; updated to coal in 1981
Boiler Rating, MMBtu/Hr for coal	225
Electrical Power Rating, Gross Megawatts	24
Description	Combustion Engineering Model CE-VU40 225 MMBtu/hr (coal), traveling grate stoker, firing only coal for primary fuel and fuel oil/coal for a cold start
Air Pollution Control Equipment	Carter Day fabric filter baghouse with 4 compartments
Emissions Reduction (%)	NO_x – None SO_2 – None PM/PM_{10} – 93+%

II. Source Emissions

CENC estimated that a realistic depiction of annual emissions for Boiler 3, or "Baseline Emissions" was the years 2006 – 2008. CENC determined that the maximum year within this scope was 2006, since it had the highest capacity factor and heat input.

Table 2 summarizes the NO_x, SO_2, and PM actual emissions averaged over the 2006 – 2008 timeframe for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's Air Pollutant Emission Notices

[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.

submitted by the facility and as applicable, EPA's CAMD Database (Boilers 4 and 5).

Table 2: Summary of 2006 - 2008 Averaged Emissions – CENC Facility

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
1,512	2,433	38

Table 3: Summary of 2006 - 2008 Averaged Emissions by Unit - CENC Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Boiler #1 (288 MMBtu/hour – natural gas fired)	*SO_2 (tons)*	*0.1*	*0.1*	*0.1*	*0.1*
	SO_2 (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*30.8*	*23.9*	*30.3*	*28.3*
	NO_x (lb/ MMBtu)	*0.02*	*0.02*	*0.02*	*0.02*
	PM_{10} (tons)	*0.8*	*0.7*	*0.8*	*0.7*
	PM_{10} (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
Boiler # 2 (288 MMBtu/hour – natural gas fired)	*SO_2 (tons)*	*0.1*	*0.0*	*0.1*	*0.1*
	SO_2 (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*32.4*	*10.4*	*27.6*	*23.5*
	NO_x (lb/ MMBtu)	*0.03*	*0.01*	*0.02*	*0.02*
	PM_{10} (tons)	*0.9*	*0.3*	*0.7*	*0.6*
	PM_{10} (lb/ MMBtu)	*0.00*	*0.00*	*0.00*	*0.00*
Boiler #3 (225 MMBtu/hour – coal fired)	SO_2 (tons)	264	205	267	245
	SO_2 (lb/ MMBtu)	0.27	0.21	0.27	0.25
	NO_x (tons)	185	150	170	168
	NO_x (lb/ MMBtu)	0.19	0.15	0.17	0.17
	PM_{10} (tons)	2.3	1.9	2.1	2.1
	PM_{10} (lb/ MMBtu)	0.00	0.00	0.00	0.00
Boiler #4 – (360 MMBtu/hour – coal fired)	SO_2 (tons)	764	815	763	781
	SO_2 (lb/ MMBtu)	0.48	0.52	0.48	0.49
	NO_x (tons)	637	589	575	600
	NO_x (lb/ MMBtu)	0.40	0.37	0.37	0.38
	PM_{10} (tons)	10.9	10.0	10.4	10.4
	PM_{10} (lb/ MMBtu)	0.01	0.01	0.01	0.01
Boiler #5 – (650 MMBtu/hour – coal fired)	SO_2 (tons)	1,598	1,333	1,289	1,407
	SO_2 (lb/ MMBtu)	0.56	0.47	0.45	0.49
	NO_x (tons)	900	614	559	691
	NO_x (lb/ MMBtu)	0.32	0.22	0.20	0.25
	PM_{10} (tons)	21	17	16	18
	PM_{10} (lb/ MMBtu)	0.01	0.01	0.01	0.01
P005 – Coal Unloading and Conveying	*PM_{10} (tons)*	*0.03*	*0.03*	*0.03*	*0.03*
P007 – Boiler #5 Silos – coal conveyor to Unit 5 silos	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P008 – Ash Handling – 11, 12, 13 – general ash silo	*PM_{10} (tons)*	*5.57*	*5.57*	*5.38*	*5.51*
P009 – Boiler #3 Silos – coal conveyor to Unit 5 silos	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P010 – Ash Handling – Boiler #4 & #5 fly ash	*PM_{10} (tons)*	*0.02*	*0.02*	*0.02*	*0.02*

collection					
P011 – Ash Handling – Fly ash silo loadout	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P012 – Ash Handling – Fly ash silo bin vent	*PM_{10} (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
P013 – Diesel Air Compressors – GM diesel engine for backup operation of air compressor	*SO_2 (tons)*	*0.00*	*0.00*	*0.00*	*0.00*
	NO_x (tons)	*0.00*	*0.00*	*0.00*	*0.00*
	PM_{10} (tons)	*0.00*	*0.00*	*0.00*	*0.00*

*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 0.44 lbs/MMBtu for Boiler 4 and 0.29 lbs/MMBtu for Boiler 5).

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

Boiler 3 currently has grandfathered status for State construction permits. This boiler is included in the current Title V permit, but does not currently have fuel usage or emission limitations for NO_x, PM, or SO_2. This boiler is subject to opacity requirements under Colorado Regulation No. 1, Section II.A.1 and a sulfur dioxide limit of 1.8 lbs/MMBtu when burning coal. Boiler 3 has a PM emission rate limit of 0.122 lbs/MMBtu and is controlled with a baghouse that was installed in the early 1980s. In addition to not utilizing a CEMS, a sophisticated automatic Data Acquisition System for control parameters, such as fuel usage, is not installed. The actual NOx emissions is based on AP-42 factors applicable to the coal type (bituminous, sub-bituminous, etc.) and coal usage based on rail car / truck unloading records. This AP-42 factor has a B-rating and may be subject to change in the future. Unit 3 is a base-loaded boiler. It's load range varies from the low end (plant reliability—ready to respond in the event of a malfunction in Unit 4 or Unit 5), medium loads (increased customer steam loads) to high loads (i.e., during Unit 4 or Unit 5 overhauls). The load range varies within the month, and has patterns throughout the year. Therefore, the Division believes that a baseline period of 2000 – 2008 is warranted for CENC Boiler 3 due to the factors listed above. The baseline emissions for Boiler 3 are further detailed in Table 4

Table 4: CENC Unit 3 Detailed Baseline Emissions

Pollutant	Unit 3 (2000 – 2008)	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO_x	205	0.21
SO_2	257	0.26
PM_{10}	2	0.037***

*Using most recent three calendar years (Division APEN data).
**The Division calculated annual average rate (lb/MMBtu) from the most recent three calendar years, the maximum heat input and annual operating hours.
***The PM_{10} emission rate is determined from the last Title V permit compliance stack test (August 24, 2007).

III. Units Evaluated for Control

As documented by CENC, this boiler fires low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 5.

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

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
B003	12,541	0.42	8.38

Table 1 lists the units at Colorado Energy Nations Golden Facility 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 CENC Boilers

Emission Unit	Pollutant	Fuel
		Coal (bituminous) (lb/ton)
Boiler 3[2]	NO_x	11
	SO_2	38 x %S = 16.0*
	PM/PM_{10}	PM – 66 PM_{10} – 13.2

*%S = % of sulfur present in coal supply. For example, 38 x 0.42 = 16.0
**%A = % of ash present in coal supply. For example, 10 x 8.39 = 83.9

It is worth noting that although Boiler 3 was on-line the majority of the time, it ran at reduced capacity due to production requirements, demonstrated in Table 7.

Table 7: Boiler 3 Baseline Capacity Factor

Heat Input (HI) (MMBtu/year)		
Potential HI	1,971,000	B3 % Potential-HI
2006	874,569	44.37%
2007	711,157	36.08%
2008	805,320	40.86%
Average	797,015	40.44%

IV. Reasonable Progress Evaluation of Boiler 3

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

CENC identified five SO_2 control options:

Flue gas desulfurization (FGD):

Lime or limestone-based (wet FGD)

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.
http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

Lime spray dry absorber (SDA or dry FGD)
Dry sorbent injection – Trona (DSI)
Fuel switching – different coal type
Fuel switching – natural gas

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.

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.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also

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[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.

bound the facility to the north and east. Table 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with SO_2, the design gas residence time in a SDA is approximately 10 seconds. For Boiler 3, a SDA vessel for each boiler, not including other associated equipment, would be approximately 27 feet in diameter by 47 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash form the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on Boiler 3.

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential SO_2 controls on Units 4 and 5. It can be reasonably assumed that this visit also applies to Unit 3. The Division noted:

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible 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 for Boiler 3.

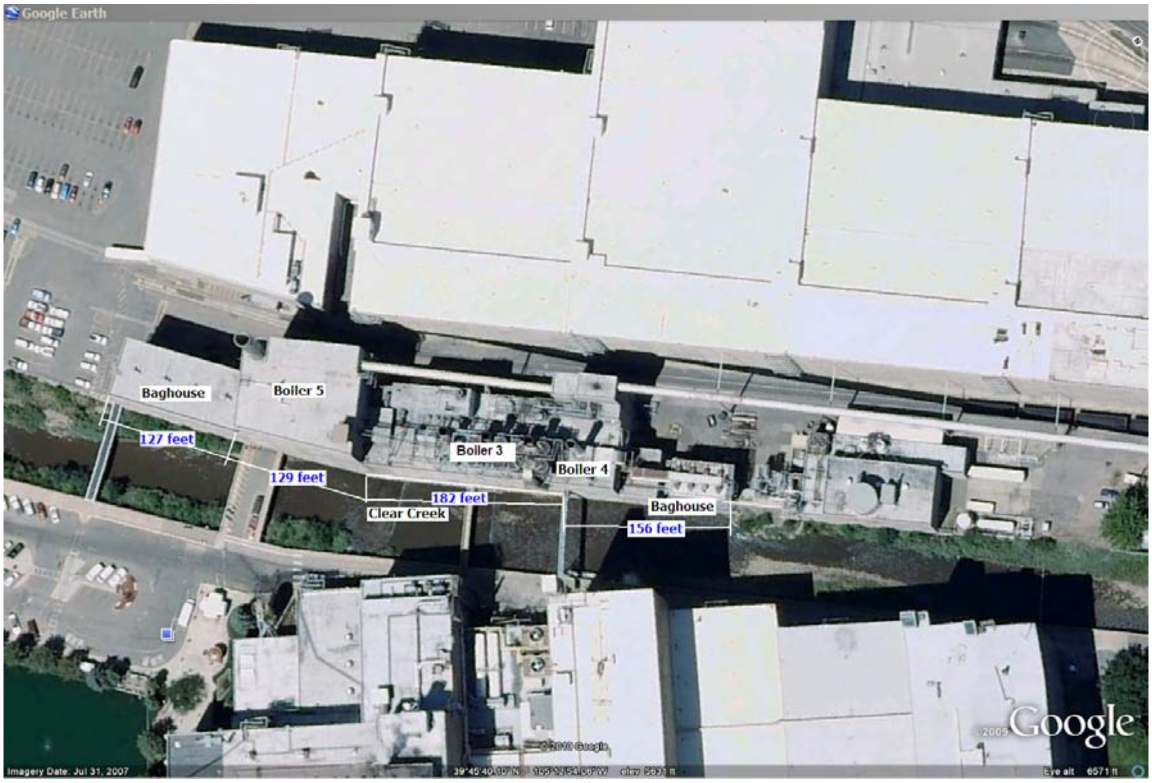

Figure 2: Aerial Zoom of CENC Facility

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, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters 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. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. 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.

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, CENC estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO_2 removal. 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. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boiler 3.

Fuel Switching – Different Coal Type: CENC asserts that the facility already utilizes low sulfur, high heating value bituminous coal from western Colorado. Typically, the coal contains only about 0.43 percent sulfur with a heating value of 12,100 Btu/lb and potential SO_2 emissions of 0.73 lb/MMBtu. The sulfur content of CENC's Colorado coal rivals the low sulfur properties of Powder River Basin (PRB) coal from Wyoming, and therefore, it represents the lowest sulfur coal available. Any shift from the purchase of local Colorado coal would have an adverse effect on Colorado mining and transportation industries.

Additionally, CENC notes that PRB coal is extremely dusty to handle, being much more friable than the Colorado coal presently used) and it generates dust through weathering much more quickly than bituminous coal. PRB coal also is subject to spontaneous combustion in and around material handling systems and silos. The generation of fugitive dust and periodic spontaneous combustion is a tremendous issue at a site such as a Coors Brewery, which precludes conversion to PRB coal. Therefore, a change in coal supply is not a feasible RP control option.

Fuel Switching – Natural gas: Natural gas offers some operating and maintenance advantages. The use of natural gas would eliminate coal handling and baghouse operating and maintenance labor as well as ash handling and disposal. Natural gas fuel switching is a feasible option for CENC Boiler 3.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC 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 CENC Boiler 3 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers.

DSI: CENC asserts that the maximum SO_2 removal rate that can be achieved to be 65% SO_2 removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals[5] and to be conservative since this technology is relatively novel.

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO_2 emissions by almost 100% from each unit using EPA's AP-42 emission factors[6] and concurs with CENC's submittal.

Table 8 summarizes each available technology options and technical feasibility for SO_2 control on CENC Boiler 3.

Table 8: CENC Boiler 3 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90%[7]	Y
Dry FGD	70 – 90% (CENC)	N
DSI (Trona)	≤65% (CENC)	Y
Fuel switching – different coal type	minimal (CENC)	N
Fuel switching – natural gas	99% (EPA AP-42)	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

CENC submitted cost estimates for DSI and natural gas fuel switching for Boiler 3 on May 7, 2010.

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. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boiler 3.

[5] Colorado Springs Utilities, 2010. "RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5." Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

[6] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[7] 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.

DSI: PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. . 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. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of SO_2 collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO_2 collected. Detailed capital and annual cost data are presented in "CENC RP APCD Technical Analysis".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI.

Table 9: DSI Cost Comparisons

Facility & Unit	Size (MW)	Annualized Costs ($/year)	Cost Effectiveness ($/ton)	Ratio ($/kW)
Colorado Energy Nations – Boiler 3	24	$1,340,661	$9,114	$55.86
Colorado Energy Nations – Boiler 4	35	$1,766,000	$3,774	$50.46
Colorado Springs Utilities – Drake Unit 5	51	$1,746,172	$2,293	$34.33
Colorado Energy Nations – Boiler 5	65	$2,094,000	$2,485	$32.22
Colorado Springs Utilities – Drake Unit 6	85	$2,910,287	$1,741	$34.24

The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.[8] CENC Boiler 3 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC's DSI cost estimates.

Fuel Switching – Natural Gas: The Division used EPA's Cost Control Manual[9] to estimate annual operating costs, of approximately $25,000 per ton of SO_2

[8] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.
[9] EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.

removed annually for Boiler 3 at the CENC facility.[10] However, it should be noted that natural gas prices vary significantly; the Division used 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[11] to determine natural gas costs. Therefore, the Division concurs that the natural gas estimates submitted by CENC on May 7, 2010 to be reasonable.

In the February 8, 2010 submittal, CENC notes that the fuel is the largest steam production cost incurred by CENC, and stresses the variability in natural gas prices. CENC also emphasized the added negative Colorado economic impact in that CENC coal is purchased from Colorado mines, which may be offset by the natural gas purchases also from Colorado-based corporations. The use of natural gas would eliminate pulverizer and baghouse operating and maintenance costs as well as ash handling and disposal costs. Other boiler maintenance costs would be reduced if coal was not burned.

Table 10: CENC Unit 3 Resultant SO2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	257	0.260	0.273
DSI - Trona	60	103	0.104	0.109
Fuel Switching - Natural Gas	100	0	0.000	0.000

Table 11: CENC Unit 3 SO2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI - Trona	154	$1,340,661	$8,709	$57
Fuel Switching - Natural Gas	257	$1,428,911	$5,569	-$31

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control

[10] Colorado Air Pollution Control Division Technical Analysis – CENC RP APCD Technical Analysis, 2010.

[11] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

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. 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 creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). 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 area) when applied to this small boiler at the CENC facility (Boiler 3).

DSI: CENC 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. 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,[12] 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 related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

Fuel Switching – Natural Gas: Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

Factor 4: Remaining Useful Life

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

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.08 Δdv for DSI applied to Boiler 4 (360 MMBtu/hr). DSI controls for Boiler 4 would reduce SO_2 emissions by approximately 268 tons per year. DSI controls for Boiler 3 would reduce SO_2 emissions by about 147 tons per year. Fuel switching to natural gas would reduce SO_2 emissions by an estimated 245 tons annually. Consequently, it is reasonable to infer, based on scaling, that either control applied to Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δdv.

[12] 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

Table 12: CENC Boiler 4 SO_2 Modeling Results

SO_2 Control Method		CENC - Boiler 4	
	Emission Reduction (tpy)	SO_2 Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	---	0.90	---
DSI - Trona	268	0.26	0.08

Determination

Table 13 illustrates fuel analysis from 2000 – 2010. The Division believes a 20% contingency factor is warranted for CENC Boiler 3 due to the factors listed on page 5. Based on Table 13, the maximum SO2 emissions from the past decade (2000 – 2010) is 0.99 lb/MMBtu. With the uncertainty factor, the Division believes that a 1.2 lb/MMBtu is appropriate for RP.

Table 13: CENC Boiler 3 Coal Supply SO2 Limit Support

	2000-2006	2006-2008	2009-2010
Minimum Btu/lb	11,068	11,221	11,444
Maximum % Sulfur	0.55	0.55	0.57
Theoretical lb/MMBtu…			
Maximum B3 Conversion Sulfur to SO2 (using fuel analysis)	0.99	0.98	0.99

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 RP is the following SO2 emission rate:

CENC Boiler 3: 1.2 lb/MMBtu

Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement (<< 0.10 dv) afforded.

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

CENC Boiler 3 is equipped with fabric filter baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Condition 2.2 requires Boiler 3 to comply with State Regulation No. 1 where the PM/PM_{10} emission limit is calculated from the equation $PE = 0.5(FI)^{-0.26}$, where PE= Particulate Emissions in lbs/MMBtu and FI = Fuel input in million Btu per hour. Additionally, Condition 18.1 mandates that each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 14 shows the most recent stack test data (August 24, 2007). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >90% control.

Table 14: CENC 2007 Stack Test Results

Pollutant	Boiler 3 (lb/MMBtu)
Filterable PM_{10}	0.037
PM_{10} Control efficiency	93.0%

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. 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.

This boiler is subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.[13] As currently proposed, the boiler will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).[14]

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of

[13] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

[14] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible (less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The state has determined that an emissions limits of 0.07 lb/MMBtu (PM/PM10 represents the most stringent control option. The unit is exceeding a PM control efficiency of 90%, and the control technology and emission limit is RP for PM/PM_{10}. The state assumes that the RP emission limit can be achieved through the operation of the existing fabric filter baghouse.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

CENC, using a similar unit's NO_x analysis[15], identified eight potential NO_x control options:

- Flue Gas Recirculation (FGR)
- Low-temperature Oxidation System (LoTOx)
- Selective Non-Catalytic reduction (SNCR)
- Rotating Over-Fire Air w/ Rotamix (ROFA)
- Fuel switching – different fuel type (natural gas)
- Regenerative Selective Catalytic Reduction (RSCR)
- High Temperature Selective Catalytic Reduction (HT SCR)
- Low Temperature Selective Catalytic Reduction (LT SCR)

The Division also identified and examined the following additional control option for this unit:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

Flue Gas Recirculation (FGR): FGR technology extracts up to 20 to 30% of the flue gas from downstream of the economizer, air heater, or particulate control equipment, and is mixed into the combustion inlet air duct. The amount of FGR

[15] "Black Hills Clark Station NO_x Reduction Feasibility Study" BH Clark Station Unit 1. Prepared by CH2MHill. December 2009.

that is achievable is determined by a boiler's operating characteristics and the ability to mix with primary air to allow for good fuel bed combustion stability. Flue gas recirculation is considered technically feasible for CENC Boiler 3.

LoTOx System: The LoTox system has the potential of significant NO_x reduction; however, the process requires operation in conjunction with a wet scrubber. CENC does not currently have a wet scrubber in service, has a limited footprint in which to locate a wet scrubber, and the Division has determined that wet scrubbers are not being considered for this facility due to non-air and energy impacts. Therefore, the LoTOx alternative is not considered due to the determination regarding wet scrubbers.

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for CENC Boiler 3.

ROFA: Nalco Mobotec markets ROFA as an improved second generation OFA system. ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. Nalco Mobotec offers the ROFA system as a stand-alone installation, or with the Rotamix feature. Rotamix is Nalco Mobotec's version of SNCR technology, and ammonia is injected into the ROFA airstream. ROFA is considered technically feasible for CENC Boiler 3.

Fuel switching – different fuel type (natural gas): Natural gas reburning technology is a staged fuel approach using an expanded volume of the furnace to control NO_x production, rather than only within the flame envelope, also referred to as Methane de-NO_x. The primary solid fuel combustion delivery and boiler location remains the same, and for the case of CENC Boiler 3 this is currently assumed to occur on the traveling fuel grate. The secondary fuel introduction point is after the primary fuel burn zone, in a fuel-rich reaction zone (the reburn zone). While other fuels may be used in the reburning zone, natural gas is most common and NO_x reductions of 30-70% may be feasible. Higher removals are associated with longer boiler residence times. Therefore, 50% was used for the analysis due to the relatively short boiler at CENC (similar to Black Hills Clark Station Unit 1). Natural gas fuel switching is considered a technically feasible alternative for CENC Boiler 3.

RSCR/HT SCR/LT 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. 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.

CENC estimated that a retrofit SCR system on Boiler 3 could achieve 0.024 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. CENC evaluated three types of SCR for this analysis – regenerative SCR, high-temperature SCR, and low-temperature SCR. These three different options were evaluated because of the potential variable inlet temperature on a spreader stoker boiler such as Unit 3. Regenerative SCR notably may not achieve the same reductions as the other two SCR options, but regardless was evaluated. All three SCR options – RSCR, HTSCR, and LTSCR – are considered technically feasible for CENC Boiler 3.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[16] 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[17] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boiler 3.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[18]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

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[16] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

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

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

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[19] 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 CENC Boiler 3 to determine control efficiencies and annual reductions.

Flue Gas Recirculation (FGR): CENC estimated a 20% NO_x reduction. Flue gas recirculation is considered an operational modification, since fuel is rearranged in the main combustion zone. EPA's AP-42 emission factor tables estimate operational modifications to reduce NO_x 10 –20%.[20] It should be noted the baseline NO_x emission rate (0.17 lb/MMBtu) is much lower than other spreader stoker boilers examined in many control case studies.[21] The Division considers this level of control optimistic and concurs with CENC's control efficiency estimates for FGR.

SNCR: CENC noted in the May 6, 2010 submittal that the similar unit was assumed to achieve 40% control for SNCR. However, CENC determined that 30% control was a more realistic estimate. EPA's SNCR Air Pollution Control Technology Fact Sheet states that SNCR achieves 30 – 50% control, which concurs with the Division's experience. The Division determined in CENC's BART analysis that an appropriate NO_x reduction estimate is 30%; therefore, the Division concurs with CENC's control efficiency estimate.

ROFA: A recent AWMA study noted that ROFA achieves from 45 – 60% NO_x reduction depending on temperature and distribution of combustion products. [22] CENC estimated a reduction of 57.1% based on a vendor guarantee for a similar unit. This results in a resultant NO_x emission rate of 0.07 lb/MMBtu. In the Division's experience, this emission rate may not be realistically achievable and will require more study if applicable.

Fuel switching – different fuel type (natural gas): CENC estimates 50% NO_x reduction by converting fuel to natural gas. This is equal to about 0.09 lb/MMBtu, which is consistent with EPA's AP-42 emission factor tables for a

[19] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[20] 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
[21] EPA, Office of Air and Radiation. "Alternative Control Technique Document – NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers." Emission Standards Division. http://www.epa.gov/ttncatc1/dir1/icboiler.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.

large wall-fired boiler controlled with flue gas recirculation (0.098 lb/MMBtu).[23] Therefore, the Division concurs with CENC's control efficiency estimate.

RSCR/HT SCR/LT SCR: CENC estimates 74.5% NO_x control for RSCR and 85.7% for HTSCR and LTSCR. These control efficiencies are consistent with 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.[24,25] RSCR will not achieve the same control efficiencies as HTSCR and/or LTSCR due to the heat input being required through burner arrangement located between two canisters and can be applied to relatively cold flue gas temperatures seen after particulate control equipment. The Division notes that these control efficiencies, due to the low baseline NO_x emission rate, result in extreme emission rates (0.02 – 0.04 lb/MMBtu) and may not be realistically achievable, but concurs with CENC's current estimate for purposes of this RP evaluation.

Table 15: CENC Boiler 3 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	n/a	N – coal stoker boiler
Flue Gas Recirculation (FGR)	~20%	Y
Selective non-catalytic reduction (SNCR)	~30 - 50%	Y
Rotating Overfire Air (ROFA)	45-60%	Y
Fuel switching – natural gas	~50%	Y
Selective catalytic reduction options (RSCR, HTSCR, LTSCR)	~75 – 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

FGR: The costs of flue gas recirculation for stoker boilers are not well documented. This type of modification is considered a pre-combustion boiler modification. This modification should be more cost-effective than other options,

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[23] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

[24] 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

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

considering that either a new FGR fan will have to be installed or that the existing forced draft (FD) fan may be used to inject the flue gas into the combustion air. The Division considers the annualized cost of approximately $280,000 for FGR to be reasonable for this small boiler.

SNCR: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of CENC Boiler 3.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[26] The CENC-estimated SNCR costs for operating expenses is about 77% for Boiler 3. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[27]

The Division calculates cost effectiveness (using CENC cost estimates) for SNCR on Boiler 3 to be about $10,150 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.[28,29] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced. [30] CENC's estimates are greater than these ranges due to the small size of the boiler, the difficulty of the retrofit, and the different boiler configuration. There is a lack of information regarding the application of SNCR to spreader stoker boiler. Therefore, the Division concludes that CENC's cost estimates for SNCR are reasonable.

ROFA: The Division notes lack of information regarding ROFA cost estimates, especially applied to spreader stoker boilers. Therefore, the Division notes that CENC's estimated ROFA annualized costs are similar to SNCR, which is a

[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] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[28] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[29] 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.
[30] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

comparable control technology in terms of achievable reductions and concludes that CENC's cost estimates for ROFA are reasonable.

RSCR/HTSCR/LTSCR: Using CENC estimates, the Division calculates that the three SCR options range from \$15,650 - \$22,300 per ton. 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.[31,32] CENC's cost estimates are much higher than this range, but the small size of the boiler, the difficulty of the retrofit, and the boiler configuration, the Division concludes that CENC's cost estimates for SCR are reasonable.

Table 16: CENC Boiler 3 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	180	0.25		56	65
Flue Gas Recirculation	20.0	144	0.15	0.17	41	47
SNCR	30.0	144	0.13	0.15	33	38
Fuel Switching - NG	34.8	118	0.12	0.14	29	33
ROFA w/ Rotamix	57.1	77	0.08	0.09	18	20
Regenerative SCR	74.5	46	0.05	0.05	11	12
High Temperature SCR	85.7	26	0.03	0.03	6	7
Low Temperature SCR	85.7	26	0.03	0.03	6	7

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

[32] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 17: CENC Boiler 3 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Flue Gas Recirculation	33.7	$278,358	$7,716	$214
SNCR	50.6	$513,197	$9,484	$98
Fuel Switching - NG	58.7	$1,428,911	$22,763	$1,534
ROFA w/ Rotamix	96.3	$978,065	$9,496	-$330
Regenerative SCR	125.6	$1,965,929	$14,629	$164
High Temperature SCR	144.5	$2,772,286	$17,933	$164
Low Temperature SCR	144.5	$3,222,223	$20,844	---

Factor 2: Time Necessary for Compliance

In the May 7, 2010 submittal, CENC notes that due to the gross estimate of this evaluation, compliance time must include a more extensive study of the control options and their technical feasibility. It is anticipated that if controls were required, at least five years after SIP approval would be needed to perform this study, work with the Division regarding the final options, incorporate the decision, and finally initiate and complete the construction process.

Factor 3: Energy and Non-Air Quality Impacts

FGR: Installation of a FGR system is not expected to impact the boiler efficiency or forced draft fan power usage significantly. Thus, this factor does not influence the selection of this control.

Fuel Switching – Natural Gas: Fuel switching to natural gas does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ROFA w/ Rotamix: The ROFA system requires installation and operation of the ROFA fans on this boiler, with a 125 hp fans being anticipated based on a similar boiler analysis. The Rota system alone will have a modest increase in power consumption. This system may result in higher levels of carbon in the fly ash due to incomplete combustion. Rotamix may impact any potential salability of fly ash due to ammonia levels. However, the Division is not currently aware of CENC selling fly ash.

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

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

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to "CENC BART Submittals" for more information.

Factor 4: Remaining Useful Life

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

Factor 5 (optional): Evaluate Visibility Results

The Division conducted CALPUFF modeling to determine the projected visibility improvement associated with various control technologies for Boilers 4 and 5 at the CENC facility. The projected visibility improvements attributed to DSI are outlined in Table 12. CALPUFF modeling indicates a 0.12 Δdv for LNB+SOFA+SNCR applied to Boiler 4 (360 MMBtu/hr). LNB+SOFA+SNCR controls for Boiler 4 would reduce NO_x emissions by approximately 368 tons per year. SCR controls for Boiler 3 would reduce NO_x emissions by about 145 tons per year. Consequently, it is reasonable to infer that either control applied to

Boiler 3, a smaller boiler at the same site (225 MMBtu/hr), would yield model results much less than 0.10 Δdv.

Table 18: CENC Boiler 4 NO_x Modeling Results

NOx Control Method		CENC - Boiler 4	
	Emission Reduction (tpy)	NOx Annual Emission Rate (lb/MMBtu)	98th Percentile Impact (Δdv)
Daily Maximum (3-yr)	---	0.67	
LNB	60	0.45	0.05
SNCR	180	0.35	0.07
LNB + SOFA	210	0.32	0.08
LNB + SOFA + SNCR	368	0.19	0.12

Determination

Based on review of historical actual load characteristics of this boiler, the Division proposes an annual NOx ton/year limit based on 50% annual capacity utilization based on the maximum capacity year in the last decade (2000). This annual capacity utilization will then have a 20% contingency factor (similar to SO_2) due to the reasons listed on page 5.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that NOx RP for Boiler 3 is following NOx emission rate

CENC Boiler 3: 246 tons/year (12-month rolling total)

Though other controls achieve better emissions reductions, the expense of these options coupled with minimal visibility improvement (<< 0.10 dv) were determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze State Implementation Plan, and thus not reasonable.

V. Reasonable Progress Evaluation of Boiler 4 and Boiler 5

Boiler 4 and Boiler 5 have been evaluated under Best Available Retrofit Technology (BART) provisions. BART for Boilers 4 and 5 can be found in Chapter 6 of the Regional Haze State Implementation Plan. The Division determines that BART represents the most stringent available NO_x, SO_2, and PM/PM_{10} control technologies and represents reasonable progress. Therefore, a full 4-factor analysis is not needed to evaluate reasonable progress for NO_x, SO_2, or PM/PM_{10} for Boiler 4 and Boiler 5 at the CENC facility.