BISON ENGINEERING, INC.

Regional Haze
Four-Factor Analysis

Colstrip Energy Limited Partnership
Rosebud Power Plant
Colstrip, Montana

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EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by Colstrip Energy Limited Partnership (CELP) to prepare a four-factor analysis for the Circulating Fluidized Bed Combustion (CFBC) Boiler located at the Rosebud Power Plant in Colstrip, Montana. The CELP facility is operated by Rosebud Energy Corporation (REC). The facility may be referenced by either name throughout this report. The four-factor analysis was requested by the Montana Department of Environmental Quality (MDEQ) in an email (and follow-up discussions) among CELP owners and staff and Craig Henrikson (MDEQ) that began on March 14, 2019.

The analysis itself relates to the second planning period (Round 2) of development of a State Implementation Plan (SIP) to address regional haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the four-factor analysis is to determine if there are emission control options at CELP that, if implemented, could be used to attain reasonable progress toward the state's visibility goals.

The four-factor analysis was conducted primarily for sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) on the CFBC Boiler at CELP. The results of the analysis have indicated that additional controls on the CFBC Boiler are not necessary to make reasonable progress due to costs and CELP's lack of a measurable impact on any nearby Class I area. It is also concluded that this facility does not qualify for additional emission controls or limitations based on the four-factor analysis. In addition, significant emission reductions that dwarf the CELP facility's emissions will take place during this planning period from the closure of Talen Energy Colstrip Units 1 and 2 later in 2019. Those emission reductions would be in very close proximity to CELP and would appear to exceed reasonable progress visibility goals for this second planning period.

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1.0 ACRONYMS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Bison	Bison Engineering, Inc.
CELP	Colstrip Energy Limited Partnership
CFBC	Circulating Fluidized Bed Combustion
CO	Carbon Monoxide
Control Cost Manual	EPA Air Pollution Control Cost Manual
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FGD	Flue gas Desulfurization
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
ID Fan	Induced Draught Fan
Lb/MMBtu	Pounds per Million British Thermal Units
MDEQ	Montana Department of Environmental Quality
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NH_3	Ammonia
NO_x	Oxides of Nitrogen
O_2	Oxygen
O&M	Operations and Maintenance
ppm_v	parts per million by volume
r	Pearson Correlation Coefficient
r^2	the square of the correlation coefficient r
RFG	Refinery Fuel Gas
RHR	Regional Haze Rule
Round 1	First planning period of the Regional Haze Program
Round 2	Second (current) planning period of the Regional Haze Program
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TSD	2008 EGU NO_x Mitigation Strategies Proposed Rule Technical Support Document
ULNB	Ultra-Low NO_x Burners

2.0 INTRODUCTION

As part of the 1977 amendments to the Federal Clean Air Act (42 USC 7401 *et seq.*) Congress declared as a national goal "… the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." [42 USC 7491(a)(1)]. With that goal, plans and requirements were eventually codified in the Code of Federal Regulations primarily in 40 CFR 51.308. (The entire visibility program is found in 40 CFR 51.300 to 309.) These requirements state individual states are required to establish "reasonable progress goals" in order to "attain natural visibility conditions" by the year 2064 [40 CFR 51.308(d)(1)].

The Environmental Protection Agency (EPA), via a Federal Implementation Plan (FIP) promulgated the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) and a four-factor analysis for various sources in Montana.[1] Additional controls for CELP were considered by EPA during that first round, but no additional controls were determined to be appropriate given the size of the facility, the cost of compliance, and minimal visibility impacts, based on overall emissions and distance to Class I areas. Therefore, the FIP did not propose nor promulgate any additional controls for this facility.

A second round of obligations is now under development, with MDEQ moving into the role as the lead agency. This second round, or planning period as it is sometimes called, requires an additional step toward reasonable progress in meeting the national goal of attaining natural visibility conditions in mandatory Class I areas by 2064. The Regional Haze Rule (RHR) as outlined in 40 CFR 51.308 *et seq*. identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. These four factors are collectively known as the four-factor analysis and are as follows:

Factor 1. Cost of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of any existing source subject to such requirements

To implement the four-factor requirement, Craig Henrikson of MDEQ contacted CELP in March of 2019. MDEQ noted this same analysis is required for other sources in the Colstrip area, namely Talen Montana, LLC's Colstrip Steam Electric Station. MDEQ followed up with an April 19, 2019, letter to further clarify various aspects of the requested analysis along with providing EPA guidelines on the matter. In a May 23, 2019, email, MDEQ requested a "representative baseline" emissions period on which to base regional modeling as a part of the Round 2 efforts. CELP chose the 2014-2016 annual emission year period as that representative baseline due to extended downtime during 2017. Those 2014-2016 annual emissions years are also used as a basis for this four-factor analysis.

[1] The FIP was promulgated on Sept. 18, 2012, at 77 FR 57864.

The Rosebud Power Plant is an electric generating facility designed to burn low-British thermal unit (Btu) waste coal from mining operations east of Billings, Montana. The facility uses a CFBC boiler that is designed to efficiently utilize low-Btu coal while also allowing a high recovery of fuel sulfur through the injection of limestone into the fluidized bed. The total design capacity of the facility is approximately 38-Megawatts of electrical generation (net).

CELP encompasses approximately 125 acres and is located approximately 6 miles north of Colstrip, Montana. The legal description of the site location is the N½ of Section 32, Township 3 North, Range 41 East, in Rosebud County, Montana. The site elevation is 3,110 feet above mean sea level.

A USGS topographic map is included as *Figure 1* showing the site location. *Figure 1* also shows the boundary of UL Bend National Wildlife Refuge, which is the nearest Class I area to CELP. *Figure 2* is a printout of a Google Earth satellite photo of the area surrounding the facility, with the site location indicated.

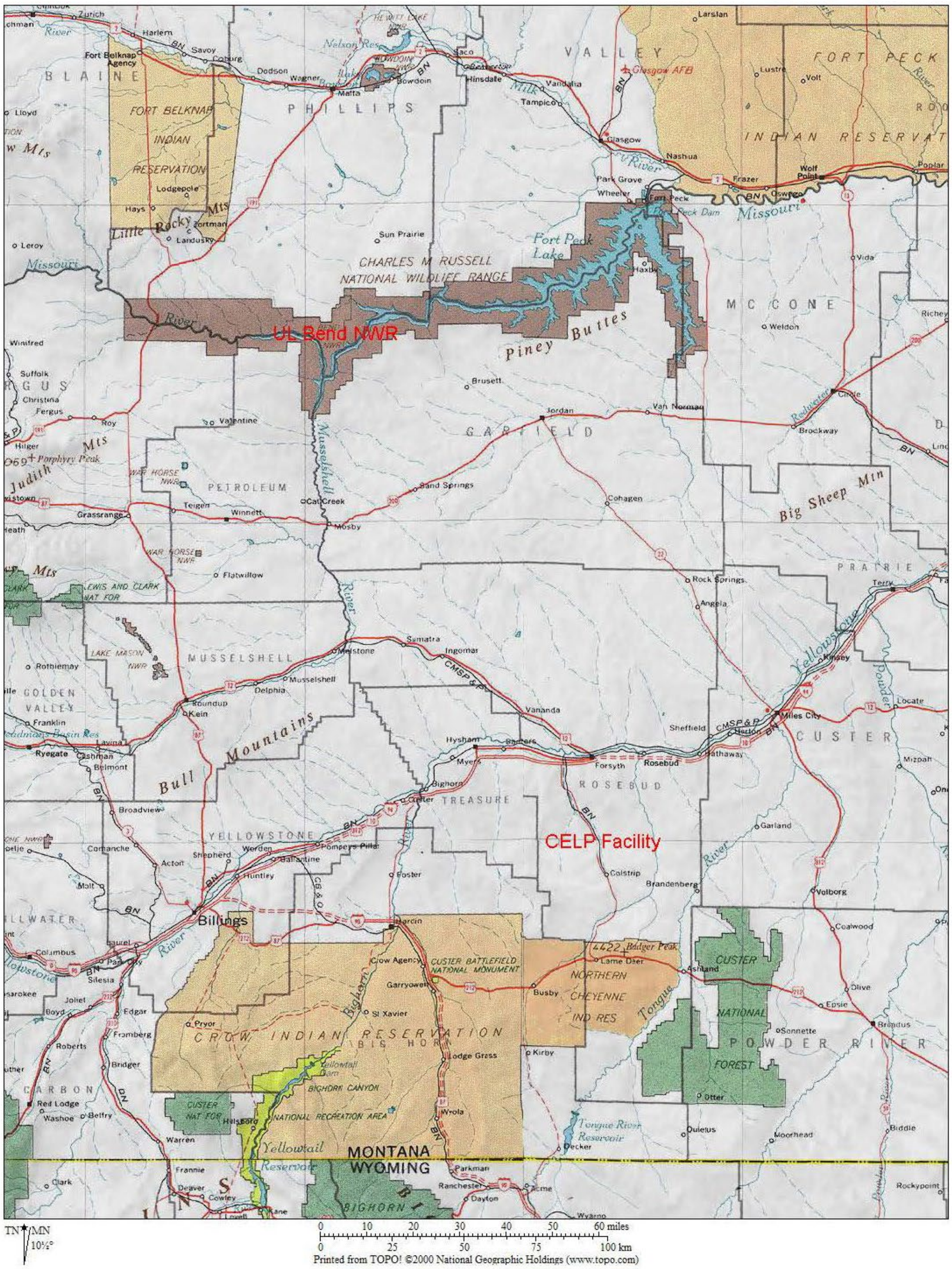

Figure 1: Topographic Map of CELP in Relation to Nearest Class I Area

Figure 2: Google Earth Representation of CELP Facility

3.0 PROGRAM SUMMARY AND STATUS

As previously stated, the Regional Haze program is an attempt to attain 'natural' (nonanthropogenic) visibility conditions in all mandatory Class I areas[2] by 2064. The Regional Haze Rule (RHR) itself was promulgated in substantially its current form in 1999 with adjustments made in 2017.[3] The rule has been implemented in incremental steps. The first step, sometimes referred to as the 1st planning period (Round 1), was a combination of BART and a four-factor analysis. During this initial planning period BART applied to certain older facilities[4] and the four-factor program applied to 'larger' facilities who had a potential of impacting (visibility) in a mandatory Class I area. CELP was reviewed with respect to the four-factor analysis under Round 1, but no additional controls were applied or required at that time.

3.1 Montana Initiatives

For Montana, the 1st planning period (Round 1) requirements were executed via the EPA. This planning period roughly included the period of 2006 to 2018. In July 2006, Montana determined that it no longer had the resources to complete the requirements of the program and returned the program to EPA.[5] Following much discussion and analyses, EPA six years later promulgated an FIP as it applied to sources in Montana.[6] As previously discussed, the FIP did not impose new or additional controls on CELP for the Round 1 planning period.

Given that the timeframe for Round 1 has expired, the RHR now requires the implementation of Round 2. Round 2 is meant to show an incremental progress toward the national goal for the 10-year period 2018 to 2028. Additional 10-year implementation periods will follow until the national goal is achieved [40 CFR 51.308(f)].

Recently MDEQ elected to bring the program back to state control. With that decision, MDEQ is taking the lead in the development of the four-factor analysis and plans associated with the second planning period. As is stands, MDEQ is attempting, by July 2021, to submit a SIP to EPA with the enforceable reductions (emission limits or plans that will go into effect prior to 2028).

To implement the program fully, it was first necessary to measure regional haze (visibility and its constituents) data in the various Class I areas. This has been an ongoing effort via various ambient monitoring programs. Among them is the Interagency Monitoring of Protected Visual Environments (IMPROVE) program [1]. This visibility monitoring program

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2 A mandatory Class I area is usually a national park or wilderness area above a certain threshold size (4,000 or 5,000 acres) and in existence on or before August 7, 1977. Montana has 12 (of 156) such areas.
3 64 FR 35765; July 1, 1999; and 82 FR 3124; Jan. 10, 2017.
4 The BART program is more fully explained in 40 CFR 51.308(e).
5 Letter from DEQ to EPA dated July 19, 2006.
6 The proposed FIP was published April 20, 2012 at 77 FR 23988 and became final on Sept. 18, 2012 at 77 FR 57864.

began in 1988 and continues to be a cooperative effort between EPA and various federal land managers (primarily the National Park Service and the US Forest Service). The results of that monitoring have indicated, for eastern Montana and Wyoming Class I areas, that the primary pollutant that accounts for the most anthropogenic (human-caused) regional haze degradation are (ammonium) sulfate and (ammonium) nitrate [2,3].

For Round 2, MDEQ has elected to look for reductions in SO_2 and NO_x (precursors to ammonium sulfate and ammonium nitrate) emissions. The sources chosen for the analysis are those facilities whose emissions-to-distance (from the Class I area) ratio exceeds a particular value as noted below:

If $Q/d > 4$, then the facility is chosen for a four-factor analysis
Q = mean annual emissions from 2014 to 2017 of $SO_2 + NO_x$ (tons)
d = distance to the nearest mandatory Class I area (kilometers)

A value greater than 4 was calculated for CELP for the given time period (10.26 specifically, based on the 2014-2017 annual emission inventory period) and was chosen by MDEQ for a four-factor analysis for Round 2.

3.2 Federal Initiatives

Because this request for information arises from the RHR, it is important to understand the nature and purpose of the visibility protection program to ascertain important criteria that will lead to the selection of specific reasonable progress requirements.

A visibility program aimed at attaining national visibility goals in mandatory Class I areas was authorized in Section 169A of the Clean Air Act (42 USC 7491). The national goals are to be attained by the year 2064, approximately 45 years from now. The rules which are to implement this goal of protecting visibility are found at 40 CFR 51, Subpart P (subsections 300 through 309). A review of Subpart P indicates the purpose and goals of the program. The purposes of the program are outlined as follows:

> "*The primary purposes of this subpart are . . .to assure* ***reasonable progress*** *toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment* ***results*** *from manmade air pollution. . ."* [40 CFR 51.300(a)].

The visibility program may be thought of as the implementation of two sub-programs. One regards new source review (NSR, PSD, etc.) and the other addresses regional haze. Regional haze may further be broken down into the BART program and the reasonable progress program. The underlying reason stated for MDEQ's March 13, 2019, letter and other correspondence to CELP relates to reasonable progress achieved through the four-factor analysis.

In that regard, the RHR outlines what it refers to as: “the core requirements” for the implementation of the regional haze goals. More specifically, 40 CFR 51.308(d)(1) states:

> “*For each mandatory Class I Federal area . . ., the State must establish goals . . . that provide for reasonable progress towards achieving natural visibility conditions.* ***The reasonable progress goals must provide for an improvement in visibility*** *for the most impaired days...”*

The rules go on to provide the states with a list of what must be considered in developing reasonable progress. Among these details are the four-factors analysis that is outlined above in *Section 2.0* and in the March 13, 2019, letter.

3.3 Overall Applicability

Montana is tasked to establish (a plan for) reasonable progress in carrying out the visibility protection. *Section 3.2* outlines the purpose of the program along with core elements. To that end, MDEQ seeks a “*detailed review of additional process controls”* which is assumed to be evaluated by both Montana and EPA for applicability in establishing a set of specific, reasonable Montana control strategies that create “Reasonable Progress” toward the 2064 goals.

The purpose of the program is to protect visibility by remedying, reducing, and preventing man-made impairments (or activities) over time in mandatory Class I areas. Reasonable progress expresses the notion that states must have implementation plans to approach the national goal by 2064 along a ‘glide-path’ of improvements to visibility, with certain exceptions. Based on the language contained in 40 CFR 51.300(d)(1), it can be ascertained that any activity, remedy or control (proposed or otherwise) that does not reasonably “improve visibility” in a mandatory Class I area is not a rational candidate for those “reasonable progress” goals [4]. That sentiment is confirmed in Section II.A EPA August 20, 2019, guidance [5]:

> *“The CAA and the Regional Haze Rule provide a process for states to follow to determine what is necessary to make reasonable progress in Class I areas. As a general matter, this process involves a state evaluating what emission control measures for its own sources, groups of sources, and/or source sectors are necessary in light of the four statutory factors, five additional considerations specified in the Regional Haze Rule, and possibly other considerations (e.g., visibility benefits of potential control measures, etc.). States have discretion to balance these factors and considerations in determining what control measures are necessary to make reasonable progress.”*

As a result, an analysis that only considers one or more emission control options is not enough for inclusion in reasonable progress mandates unless those emission controls are expected to improve actual visibility in a Class I area in a discernible manner. It is neither necessary nor appropriate to include an emission control as part of a reasonable progress goal or plan without a reasonable expectation of a resulting improvement in regional haze as a direct result of the application of the control (i.e., a discernible improvement in deciviews[7] in a Class I area.

To that end, CELP has elected to not only analyze various control "options" utilizing four-factors, but has also included a qualitative analysis of impacts this facility may have on several nearby mandatory Class I areas.[8] This was accomplished to determine if either the current configuration or future control options would fulfill the underlying need of the program to "***provide for an improvement in visibility***" per 40 CFR 51.308(d)(1) at a mandatory Class I area [6].

As will be presented in following sections of this document, no measured evidence of any impact by CELP's operations on the visibility in any mandatory Class I airshed was established.

[7] The definition of a deciview is as follows: Deciview haze index=10 $\ln_e(b_{ext}/10\ Mm^{-1})$. This is taken from the definitions found in 40 CFR 51.301. There are, of course, numerous articles and explanations for the deciview metric. One article may be found in the publication "IMPROVE," Volume 2, No. 1, April 1993 which was written by Pitchford and Malm, 1993. From a non-mathematical point of view, the change in deciview of "1" is intended to represent a "just noticeable change" (or sometimes referred to as 'just discernible') in visibility regardless of the baseline visibility.

[8] The nearest Class I area (UL Bend National Wildlife Refuge) is about 190 kilometers from the CELP facility.

4.0 REASONABLE PROGRESS PERSPECTIVE

The first few sections of this report have provided a summary of the overall regional haze program and the nature of Round 2 of implementation. It also outlined the program's basic elements and background. This section of the report describes the efforts already taken to reduce emissions not only from the state, but in the Billings area in particular. This review and discussion lead one to conclude that enough reductions have or are about to be achieved which, by themselves constitute (more than) reasonable progress within the meaning of the RHR [6].

4.1 National Emissions

A national downward trend of industrial emissions of sulfur dioxide and oxides of nitrogen has been evidenced for many years. *Figure 3* depicts the nation-wide emission rate of these two compounds from 1990 through 2017.

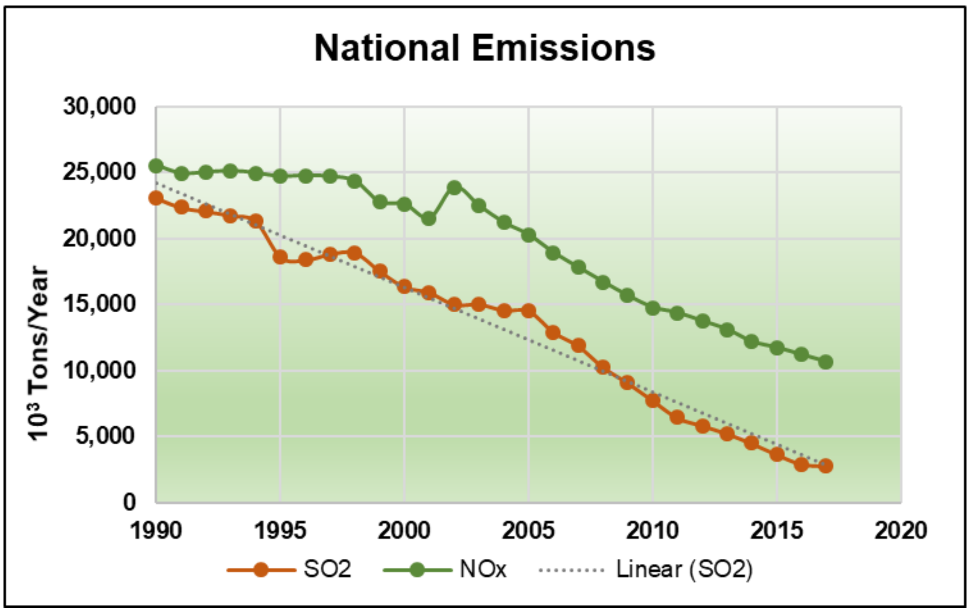

Figure 3: National Emission Trends of SO_2 and NO_x

The reductions observed over these years have occurred for many reasons mostly relating to requirements in the Federal Clean Air Act, the Montana Clean Air Act and industrial facility shutdowns.

While Figure 3 provides a historical perspective, it is also of interest to explore those emissions recorded at the start of the RHR program (2000) as shown in Figure 4. This graphic denotes SO_2 emissions through 2064 since that is the year in which the national goal is to be achieved.

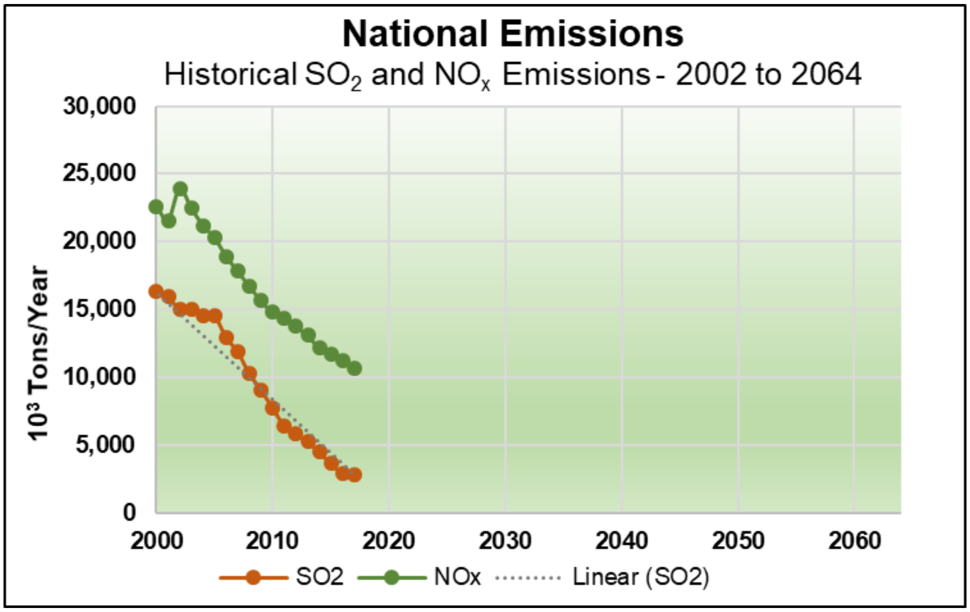

Figure 4: Historical SO_2 and NO_x Emissions

From a national perspective, it appears that emissions of SO_2 and NO_x are on a fast-downward trend. While emissions will not likely achieve "zero" by 2064, substantial reductions have and will likely continue to occur. Regardless of the decisions to be reached for Round 2, national emissions contributing to regional haze are anticipated to decline with or without any observed visibility impairment.

4.2 Montana Emissions

As depicted in Figure 5, the Montana trend in lowering industrial emissions follows the same general pattern as the national data. Except for a modest spike in NO_x emissions around year 2000, there has been a marked reduction in both NO_x and SO_2. It can be inferred that Montana has been doing its part to reach the national goal.[9]

[9] This statement presumes (without admission or proof) an *a priori* cause and effect between Montana emissions and observed visibility in any nearby Mandatory Class I area. For reasons that will be forthcoming in the September four-factor analysis, there is, in our opinion, no cause and effect relationship between CELP's NOx and SO_2 emissions in particular and a measurable impact on visibility (expressed in deciviews).

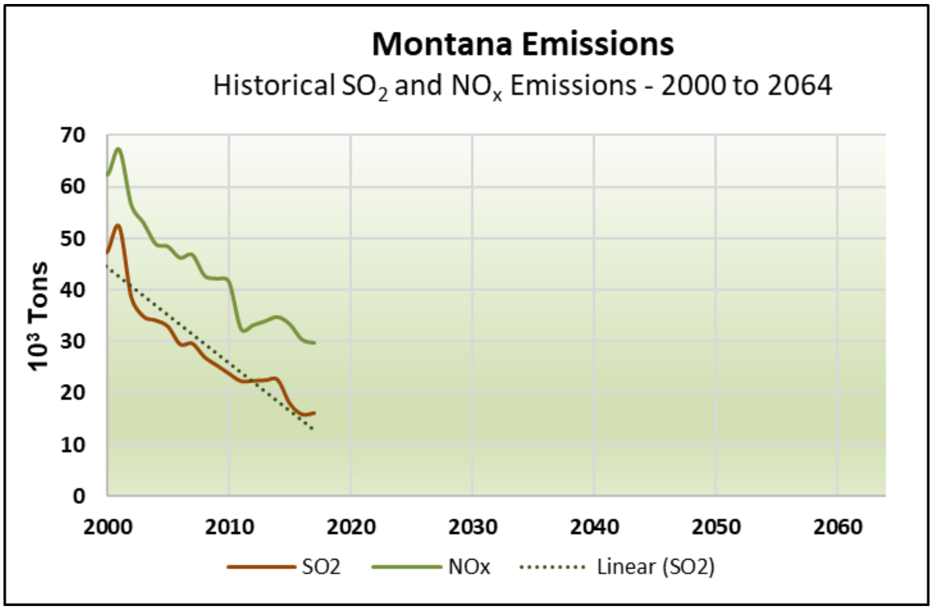

Figure 5: Montana Industrial SO_2 and NO_x Emissions

Regardless of the decisions to be reached for Round 2, industrial emissions within the state of Montana contributing to regional haze are anticipated to decline with or without any observed visibility impairment.[10]

In addition, significant emission reductions that dwarf the CELP facility's emissions (by almost a factor of 10) will take place during this planning period from the closure of Talen Energy Colstrip Units 1 and 2 later in 2019. Those emission reductions would be in very close proximity to CELP and would appear to exceed reasonable progress visibility goals for this 2nd planning period.

4.4 CELP Emissions and Perspectives

As this request for information arises from the RHR it is important to understand the nature and purpose of the visibility protection program to ascertain important criteria that will lead to the selection of specific reasonable progress requirements.

As previously discussed, additional controls for CELP were considered by EPA during the first planning period, but no additional controls were determined to be appropriate given the size of the facility, the cost of compliance, and minimal visibility impacts, based on overall emissions and distance to Class I areas. Therefore, the FIP did not propose nor promulgate any additional controls for this facility.

[10] It is assumed for this particular discussion alone that a reduction in emissions (SO_2 and/or NOx) has a direct causal relationship with improved visibility. Analyses to follow will show that this is not the case. A reduction in Montana emissions, CELP included, does not translate to an improvement in Class I visibility, linear or otherwise.

In the broader perspective, Montana shows substantial and adequate reductions in SO_2 and NO_x emissions in the period since 2000 (and earlier although not shown in the figures as a matter of convenience). These reductions have resulted from voluntary source actions, implementation plans, plant closures, new plant constructions, and numerous consent decrees. As previously mentioned, Montana's emissions reductions as well as the reductions anticipated from 2019 closure of Colstrip Units 1 and 2, are clear evidence that emission reductions are anticipated to be ahead of any desired "uniform rate" of visibility improvement or progress contemplated to date at any nearby Class I area [7].[11] The "uniform rate of progress" line is also referred to as the glidepath, which is the linear representation of the visibility improvement needed to get from the baseline at a Class I area to its "natural background" in 2064.

To be consistent with previous historical (and projected) emission summaries, the same information is provided graphically below for the RHR program history.

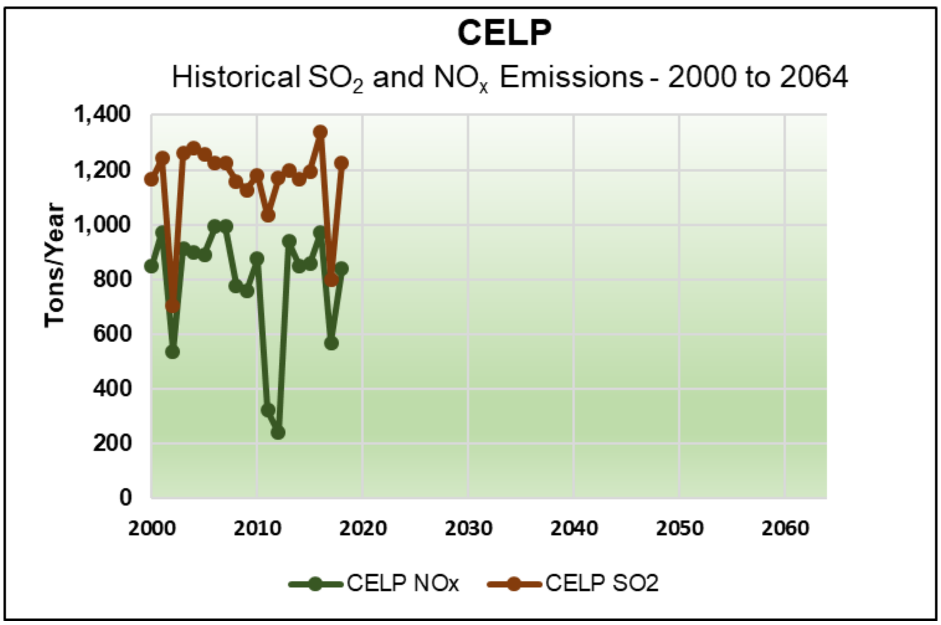

Figure 6: CELP SO_2 and NO_x Emissions from 2000 to 2064

Given the very efficient nature of the CFBC Boiler and the nature of CELP's business in generating electricity, the consistent operation and emission profile is to be expected. Consistent operations, however, do not correlate to visibility impairment. Conversely, the years of lower emissions at CELP *also* do not correlate to visibility improvement, as will be shown graphically at each relevant Class I area.

[11] These uniform rates of progress for Montana's Class I areas are taken in general terms from those "glidepaths" shown in "State of Montana Regional Haze, 5-Year Progress Report," MDEQ, August 2017, Appendix C, Figures 9, 31, 42, 64, 53, 75, 86, 97 and 108.

4.5 Emissions vs. Visibility Impairment Analysis

The next step in the reasonable progress perspective is to analyze the current and historical visibility measurements against emissions. A review of anthropogenic sources, and to what extent these sources actually impact the Class I area of interest, was completed to determine the anthropogenic impact on visibility. There are several methods one may employ to determine if any emission reduction would lead to an improvement in visibility at 'nearby' Class I areas. This analysis reviews the information in retrospect, and also discusses how that data informs predictions of future visibility impacts.

In order to consider the results of a four-factor analysis as described by the RHR, there must be first and foremost a reasonable probability of an actual improvement in visibility impairment from CELP itself or combined with other nearby sources.

In addition to emissions data, there is concurrent visibility data at all the nearby Class I areas. Visibility data from these areas was taken from the Western Regional Air Partnership (WRAP)[8] and generated from the Interagency Monitoring for Protected Visual Environments (IMPROVE)[1,2,9]. These areas and their closest proximity to CELP are shown below.

Table 1: Nearby Class I Areas and Proximity

Nearby Class I Area	Approximate Distance from CELP (*kilometers*)
UL Bend National Wildlife Refuge	188
Theodore Roosevelt National Park	250
North Absaroka Wilderness Area	260
Yellowstone National Park	280
Gates of the Mountains Wilderness Area	410

Emissions data from CELP is provided for both the baseline period for the visibility program (2000 to 2004) as well as Round 1 (2005 to 2018) with respect to those Class I areas. As stated previously, Round 1 encompassed the analysis and implementation of BART along with a four-factor analysis that took place concurrently.

It is possible to glean some insight as to whether the visibility data is responding to changes in emissions during the same time period. If CELP has a measurable impact on visual impairment at a Class I area, then the observed visibility (using deciviews as the indicator) would follow the trend. Due to a myriad of statistical confounding variables, meteorology among them, it would not be expected that this correlation between emissions and visibility (deciviews) would be necessarily linear or strong. Nonetheless, if CELP has a relatively consistent emissions profile during the monitoring period (2000 to present), it is logical to assume that the deciview parameter would follow this trend.

The sections below provide such a comparison between emissions and various nearby Class I areas, first graphically, then with respect to statistical correlation.

4.5.1 UL Bend National Wildlife Refuge Visibility vs Emissions

Another Class I area to consider is the UL Bend National Wildlife Refuge. This area is located about 190 kilometers NNE of the CELP facility. A graphical review of the emissions and visibility data over time is provided below.

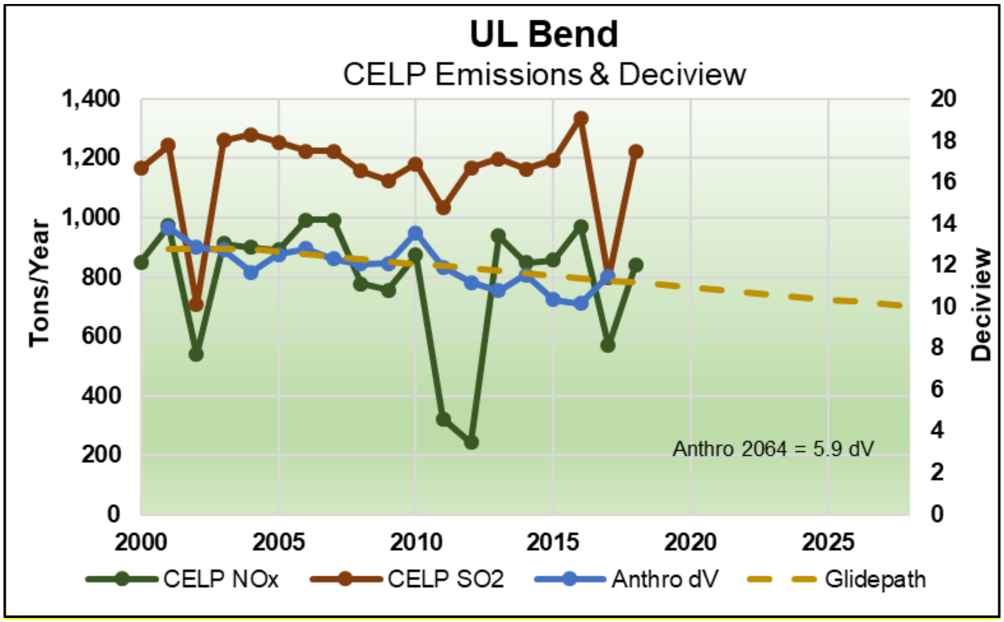

Figure 7: CELP SO_2 and NO_x Emissions from 2000 to 2018 Compared with the UL Bend National Wildlife Refuge Visibility Glidepath Through 2028

The analysis starts by a graphical review of the emissions and visibility data over time. The figure compares visibility (Anthro dV refers to anthropogenic deciview impairment) and the RHR glidepath at the UL Bend National Wildlife Refuge with CELP SO_2 and NO_x data. The glidepath refers to the line of projected improvements from the starting point of the RHR in 2000-2004 to "natural background" in 2064. Each Class I area has its own glidepath, specific to its visibility degradation baseline.

The graphic seems to indicate that the glidepath and observed deciview data match relatively closely. Thus, data to date shows that the area is meeting the uniform rate of progress (glidepath) that RHR prescribes. The variation seen in CELP emissions (from extended shutdown periods in 2017, for example) are not reflected in improved/lower deciview values.

To complete the evaluation a correlation analysis is also presented in *Appendix A.* Specifically, the Pearson Correlation Coefficient (r) was determined. The correlation coefficient measures the linear correlation between two variables as shown in Appendix

A, for example comparing CELP's NO_x and SO_2 emissions with the glidepath (multiple variables are compared). The value of "r" may vary from -1 to +1. A value of -1 indicates a negative correlation (when one variable increases, the other variable decreases). A value of zero indicates no correlation whatsoever and a value of +1 indicates a positive correlation.

The other variable of interest is r^2 (the square of the correlation coefficient r). This variable is useful because it gives an indication of the strength of a correlation. In general, the r^2 value is an indication of what percentage of the data fits the linear model of a correlation between the two variables. For example, an r^2 value of 0.50 would indicate that roughly 50% of the data fits the linear model well. Or, put another way, 50% of the data suggests a good linear correlation and 50% of the data suggests no correlation.

In this instance, CELP NO_x values had essentially no relation to Anthro dV (overall human-caused visibility impairment)[12] and Anthro NO_3 (the portion of anthropogenic visibility impairment tied to NO_3 compounds) at r values of 0.0.14 and 0.35, respectively. Correspondingly, only 0.02 and 0.12 of the data (for Anthro dV and Anthro NO_3) would fit the linear model, based on the r^2 value (confirmation of no correlation). The full Talen Energy Colstrip Units 1-4 emissions were also evaluated to see how their emissions may relate to Class I visibility. The Colstrip NO_x values had an r value of 0.67 for the Anthro dV and 0.92 to the glidepath (with 0.45 and 0.85 r^2 values, respectively), indicating some linear correlation between the Colstrip units and visibility/glidepath at UL Bend.

4.5.2 Theodore Roosevelt National Park Visibility vs. Emissions

Another Class I area of interest is the Theodore Roosevelt National Park. This Class I area is approximately 250 kilometers from CELP and is unlikely to be impacted by CELP SO_2 or NO_x emissions. The visibility versus emissions information is presented in graphical form below.

[12] The term anthropogenic deciview here is in reference to the definition of "Most impaired days" per 40 CFR 51.301.

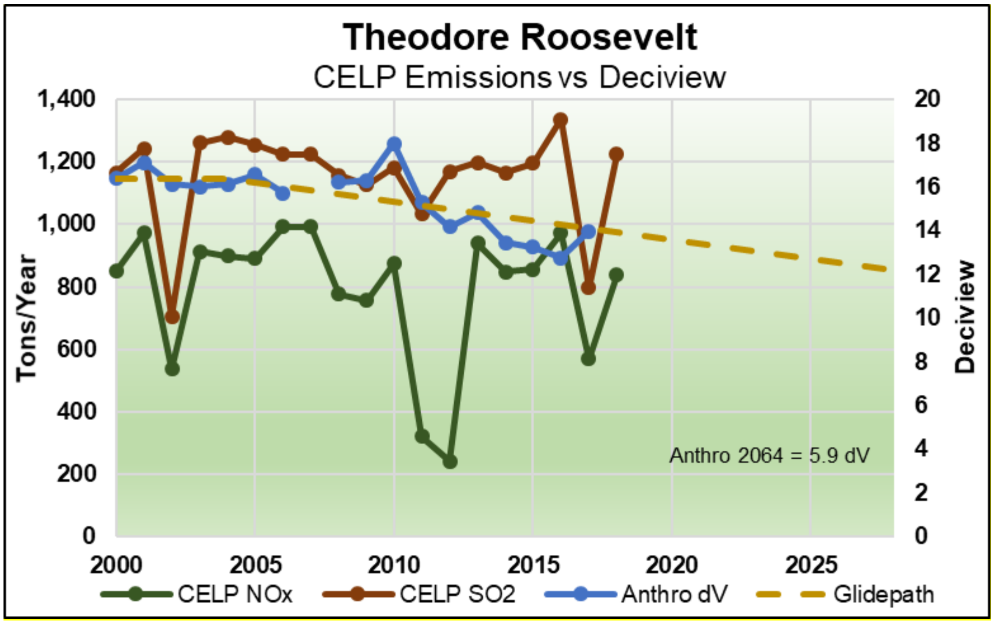

Figure 8: CELP SO_2 and NO_x Emissions from 2000 to 2018 Compared with Theodore Roosevelt National Park Visibility Glidepath Through 2028

Although not specifically portrayed in the graphic, there is a notable trend in visibility improvement in the past 10 years. This corresponds to the same 10-year period of implementation of the 1st planning period. The emissions from CELP do not share this same trend as CELP sees a more consistent emissions profile (and operation) over time. No improvement in visibility was shown during CELP's downtime.

No statistical correlation was observed with the visibility data and CELP's emissions; however, a fairly strong correlation is observed for Colstrip Units 1-4 SO_2 data, Anthro dV and Anthro SO_4 (the portion of anthropogenic visibility impairment tied to SO_4 compounds). The statistical analysis is available in *Appendix A*.

4.5.3 North Absaroka Visibility vs. Emissions

An additional Class I area for consideration is the North Absaroka Wilderness Area. It is roughly 260 kilometers from the facility to the border of the wilderness area. As with the analyses that follow, the visibility/glidepath data used in this analysis were taken from the WRAP Technical Support System [1,2].

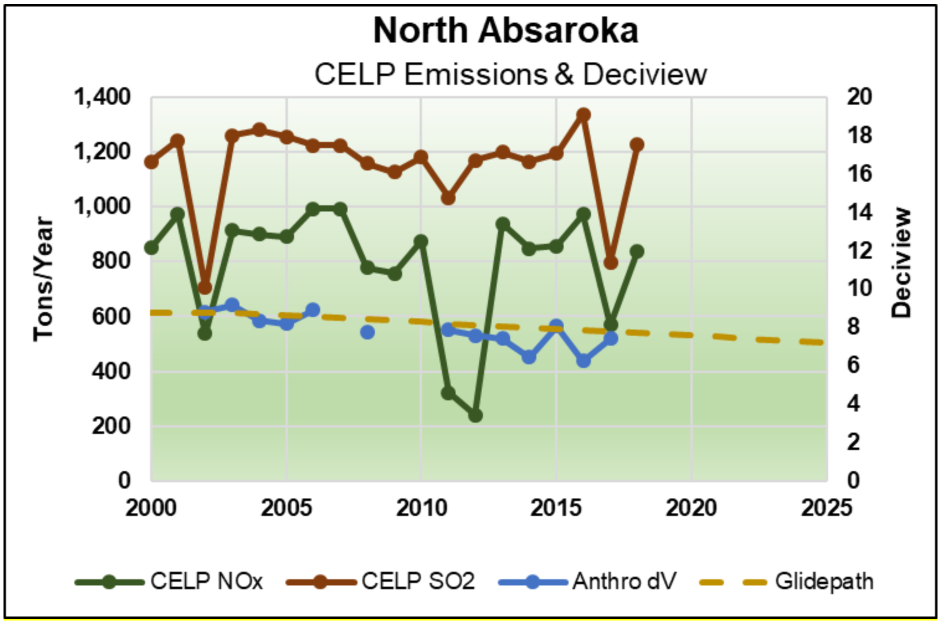

Figure 9: CELP SO_2 and NO_x Emissions from 2000 to 2018 Compared with the North Absaroka Wilderness Area Visibility Glidepath Through 2028

The most important observation to be gleaned from this chart is that the observed deciview data indicates that this Class I area is already exceeding the uniform rate or progress requirement on its glidepath. If there is no change in emissions from all SO_2 and NO_x sources and all other parameters remain the same, the North Absaroka area will have achieved the glidepath at the end of 2028 without any reductions required during Round 2.

Similar to Theodore Roosevelt National Park above, no statistical correlation was observed with the visibility data and CELP's emissions, however, a relatively strong correlation is observed for Colstrip Units 1-4 SO_2 data, the glidepath, and Anthro SO_4 (the portion of anthropogenic visibility impairment tied to SO_4 compounds). The statistical analysis is available in *Appendix A*.

4.5.4 Yellowstone National Park Visibility vs. Emissions

Yellowstone National Park is the next Class I area for consideration. It is roughly 280 kilometers from the facility to the border of the national park. The figure compares visibility (Anthro dV) and the RHR glidepath at Yellowstone National Park with CELP SO_2 and NO_x data. In reviewing the figure below, the observed visibility at the site seems, on the whole, to be following the designed glidepath.[13] The graphical data from CELP appear to be unrelated to the Yellowstone visibility data.

[13] The "glidepath" is a straight line of deciviews starting at the baseline (≈ 2000-2004) through the 2064 endpoint of the RHR program. The "endpoint" is the final desired deciviews which represents "remedying of … existing impairment of visibility … which … results from manmade pollution." (Clean Air Act). If visibility is

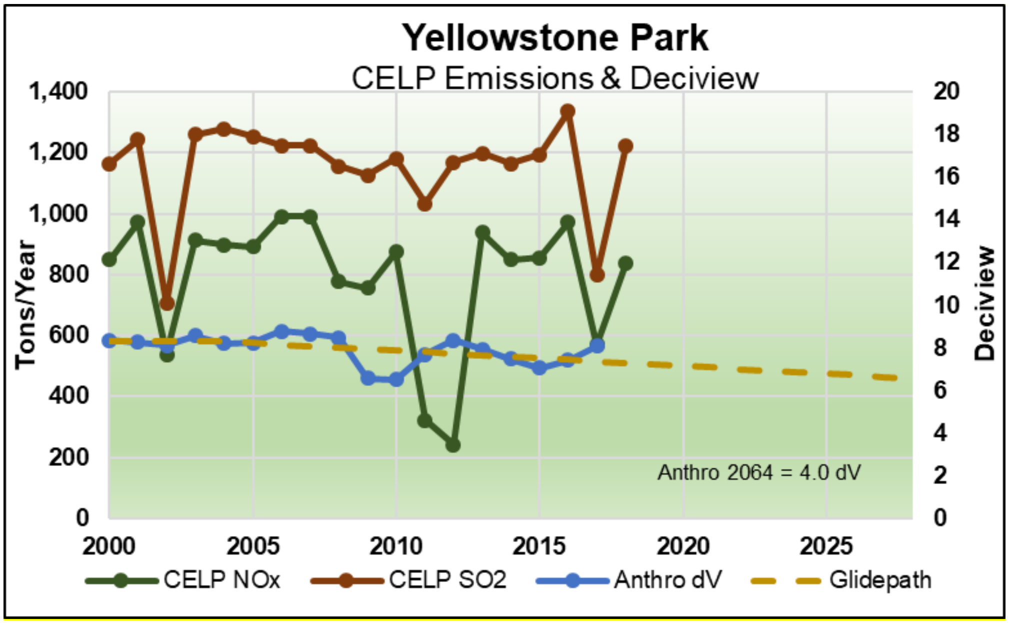

Figure 10: CELP SO_2 and NO_x Emissions from 2000 to 2018 Compared with the Yellowstone National Park Visibility Glidepath Through 2028

The full correlation analysis results are available in Appendix A, but no evident correlations are seen for CELP. The glidepath seems to be trending in the same direction as Colstrip Units 1-4 NOx and SO_2, but the emissions and visibility seem less related.

4.5.5 Gates of the Mountains Wilderness Area Visibility vs. Emissions

The Gates of the Mountains Wilderness Area was selected as another Class I area to review for completion purposes. Tthe area is about 410 kilometers WNW of the CELP facility making it an area very unlikely to be impacted by CELP. Nonetheless, a review of that data was undertaken. A graphical review of the emissions and visibility data over time is provided below.

following this glidepath it is evidence of reasonable progress towards the national goal.

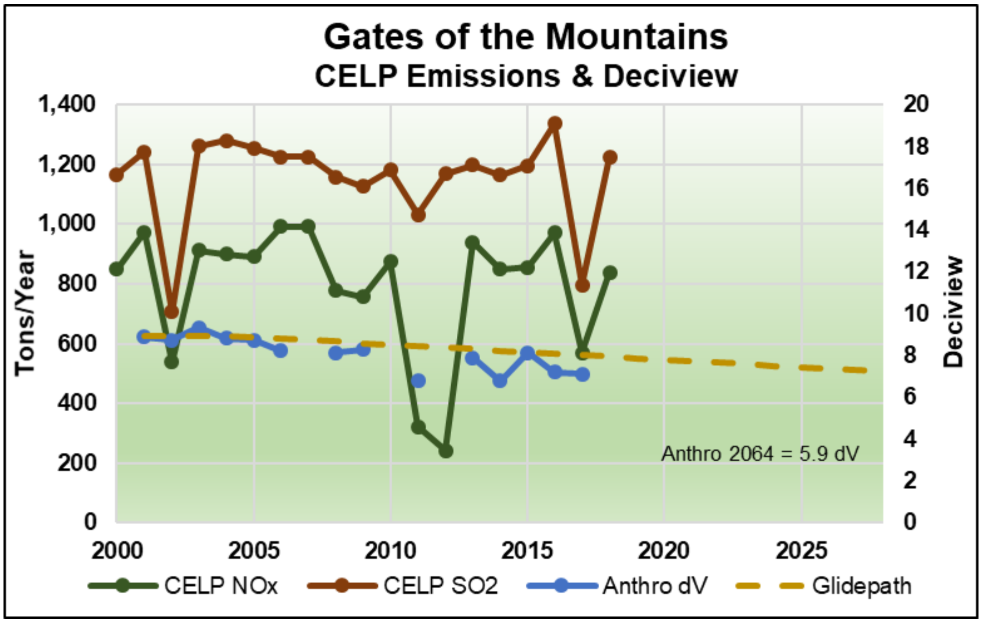

Figure 11: CELP SO_2 and NO_x Emissions from 2000 to 2018 Compared with Gates of the Mountains Wilderness Area Visibility Glidepath Through 2028

The graphic reveals two interesting features. The visibility improvement is ahead of the desired uniform rate of progress wanted for the program. And the current visibility (mean for past five years) is at or near the desired level for this 2nd planning period.

Given the distance and general wind direction, any relation of CELP emissions to Gates of the Mountains visibility seems implausible. No correlation is seen with CELP data. Surprisingly, there appear to be correlations between Colstrip Units 1-4 emissions data and Gates of the Mountains visibility. However, correlations do not always equal causation and, as with all of this information, it must be viewed as a whole.

5.0 FOUR-FACTOR ANALYSIS

The following four-factor analysis was completed for CELP in response to the March 13, 2019, email from MDEQ. This facility was selected by MDEQ because of a “Q/d” analysis used by MDEQ to screen facilities for Round 2.[14] MDEQ’s analysis used 4.0 as the action threshold for determining enrollment in Phase 2. The CELP facility had a Q/d of 10.26, over the action threshold, when utilizing 2014-2017 average annual emissions. As previously mentioned, additional controls for CELP were considered by EPA during Round 1 using the four-factor analysis and process. That analysis is revisited and updated for this discussion.

The following outlines the analysis for this source using primarily the direction of the EPA Draft Guidance [10] and the WRAP 2009 four-factor analysis [11]. The initial step in the four-factor analysis was to identify possible additional control options for this source. The options chosen include control techniques addressed in guidelines published by EPA, the EPA Cost Control Manual, BART analyses, and National Association of Clean Air Agencies (NACAA).

5.1 SO_2 Control Measures

Several techniques can be used to reduce SO_2 emissions from fossil fuel combustion sources. SO_2 control options can be divided into pre-combustion strategies (e.g., combusting low sulfur fuels, fuel blending, coal cleaning, etc.), combustion techniques (e.g., types of boilers, turbines, etc.), and post-combustion controls (e.g., wet scrubbers, dry scrubbers, etc.).

CELP currently controls SO_2 emissions using limestone injection. Limestone is injected with the waste coal prior to its combustion in the boiler. In the boiler, the limestone calcines to lime and reacts with SO_2 to form calcium sulfates and calcium sulfites. The calcium compounds are removed as particulate matter by the baghouse. Depending on the fuel fired in the boiler and the total heat input, CELP must control SO_2 between a 70% to 90% reduction per Montana Operating Permit #OP2035-03. The current limestone injection system is operating at or near its maximum capacity and increasing limestone injection beyond the current levels results in plugging of the injection lines, increased bed ash production which can reduce combustion efficiency, and increased particulate loading to the baghouses. Increasing limestone injection beyond its current level would require major upgrades to the limestone feeding system and the baghouses. Furthermore, an upgrade to the existing limestone injection system would expect only modest increases in SO_2 removal efficiency compared to add-on SO_2 control systems which were further analyzed within this section. Therefore, upgrading the existing system is not considered further. This analysis will focus on add-on control systems for SO_2 control.

[14] See email letter from MDEQ dated March 13, 2019.

5.1.1 SO_2 Control Technologies Considered

As CELP's fuel type (waste coal), type of boiler (Circulating Fluidized Bed Combustion), and the limestone system are operating at current maximum capacity, this cost analysis will focus on post-combustion controls to further reduce sulfur dioxide emissions beyond the existing limestone injection control. The post-combustion controls that are potentially technically feasible in this application are flue gas desulfurization (FGD) systems. FGD options for the CFBC boiler include: Wet Lime Scrubber, Wet Limestone Scrubber, Dual-Alkali Scrubber, Spray Dry Absorber, Dry Sorbent Injection, Circulating Dry Scrubber, and Hydrated Ash Reinjection. Each control system is briefly described as follows.

Wet Lime Scrubber

The wet lime scrubbing process uses alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed into the exhaust stream and reacts with the SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product. The waste by-product is mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

Wet Limestone Scrubber

Wet limestone scrubbers are very similar to wet lime scrubbers. The use of limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed.

Wet lime/limestone scrubbers can achieve SO_2 control efficiencies of approximately 95% or greater when used on boilers burning higher sulfur bituminous coals but may be less on lower sulfur coals. The actual control efficiency of a wet lime/limestone FGD system depends on several factors, including the uncontrolled SO_2 concentration entering the scrubber. Similar to wet lime scrubbers, wet limestone scrubbers generate sludge that can create material handling and disposal issues.

Dual Alkali Wet Scrubber

Dual-alkali scrubbers use a sodium-based alkali solution to remove SO_2 from the combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagents absorb SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, and the regenerated sodium solution is returned to the absorber loop.

The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units; however, additional regeneration and sludge processing equipment is necessary.

A sodium-based scrubbing solution, typically consisting of a mixture of sodium hydroxide, sodium carbonate, and sodium sulfite, is an efficient SO_2 control reagent. However, the process generates a sludge that can create material handling and disposal issues. The control efficiency is similar to the wet lime/limestone scrubbers at approximately 95% or greater. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

Spray Dry Absorber

The typical spray dry absorber (SDA) uses lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with an SDA typically includes an alkaline storage tank, mixing and feed tanks, atomizer, spray chamber, particulate control device, and recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use.

SDAs are the commonly used dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 95% SO_2 reduction. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

Dry Sorbent Injection

Dry sorbent injection (DSI) involves the injection of powdered or hydrated sorbent (typically alkaline) directly into the flue gas exhaust stream. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and injection device. The dry sorbent is typically injected countercurrent to the gas flow through a venturi orifice. An expansion chamber is often located downstream of the injection point to increase residence time and contact efficiency. Particulates generated in the reaction are controlled in the system’s particulate control device.

SO_2 control efficiencies for dry sorbent injection systems are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal can be achieved. These systems are commonly called lime spray dryers. Once again, control efficiencies are highly dependent upon the uncontrolled SO_2 concentration entering the scrubber.

Circulating Dry Scrubber

The circulating dry scrubber (CDS) uses a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by-product produced by this system is routed with the flue gas to the particulate removal system.

Hydrated Ash Reinjection

The hydrated ash reinjection (HAR) process is a modified dry FGD process developed to increase utilization of unreacted lime (CaO) in the CFBC ash and any free lime left from the furnace burning process. The hydrated ash reinjection process will further reduce the SO_2 concentration in the flue gas. The actual design of a hydrated ash reinjection system is vendor-specific. In a hydrated ash reinjection system, a portion of the collected ash and lime is hydrated and re-introduced into a reaction vessel located ahead of the fabric filter inlet. In conventional boiler applications, additional lime may be added to the ash to increase the mixture's alkalinity. For CFBC applications, sufficient residual CaO is available in the ash and additional lime is not required.

5.1.2 Eliminating Technically Infeasible Options

CDS systems result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across a fabric filter would be unacceptable; therefore, electrostatic precipitators (ESP) are generally used for particulate control. CELP has a high efficiency fabric filter (baghouse) in place. Based on limited technical data from non-comparable applications and engineering judgment, it has been determined that CDS is not technically feasible with a CFBC boiler equipped with a fabric filter for particulate control. Therefore, CDS will not be evaluated further.

The CELP facility has a limited area to install additional SO_2 controls that would require high quantities of water and dewatering ponds (see *Figure 12*). The wet FGD scrubber systems with the higher water requirements (Wet Lime Scrubber, Wet Limestone Scrubber, Dual Alkali Wet Scrubber) would require an on-site dewatering pond or an additional landfill to dispose of scrubber sludge. Due to CELP's limited available space, its proximity to the East Armels Creek to the east of the plant and an unnamed creek to the south of the plant, and limited water availability for these controls, these technologies are considered technically infeasible and will not be evaluated further.

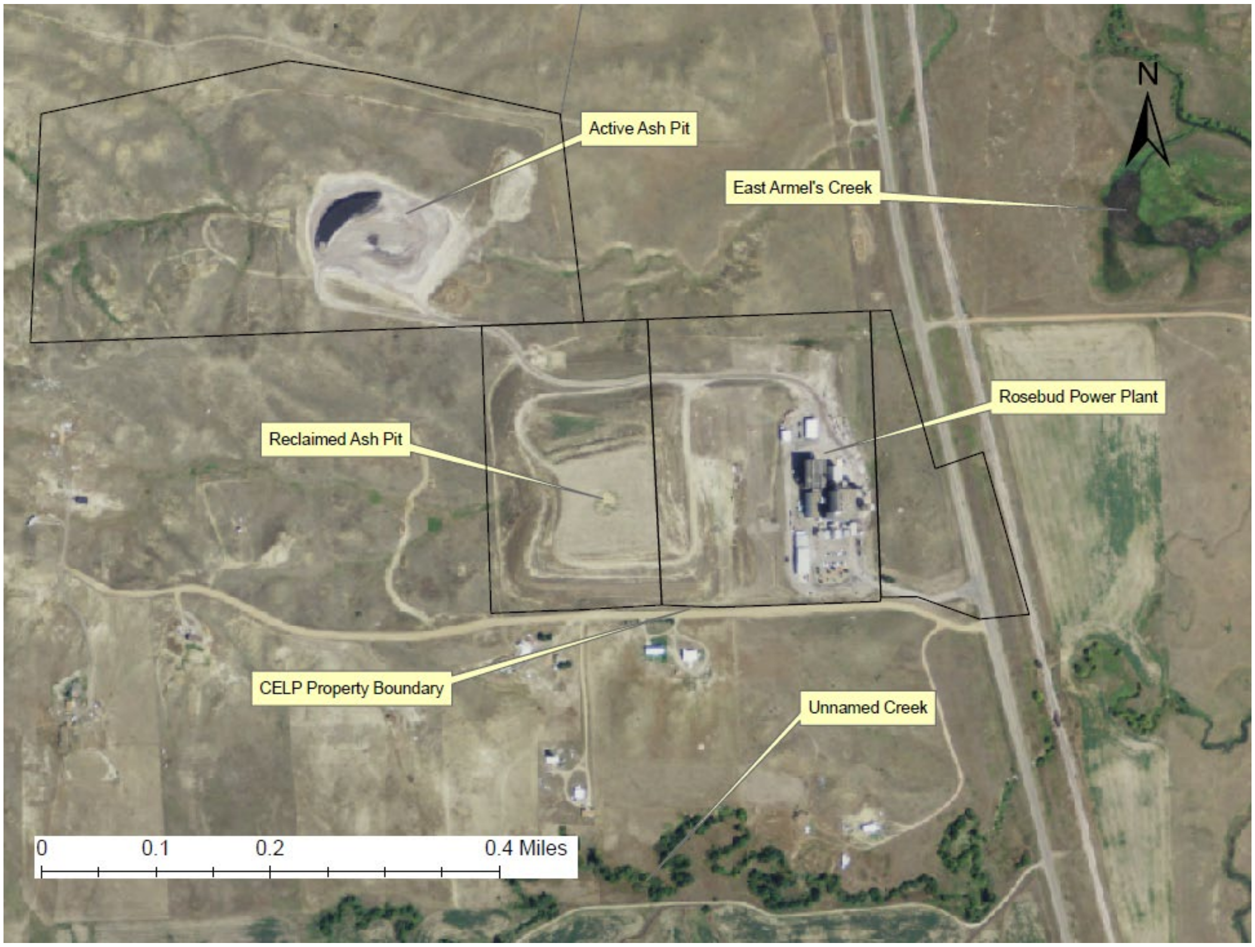

Figure 12: CELP Property Boundary and Adjacent Creeks

5.1.3 Identify Technically Feasible Options

Technologies requiring low amounts of water and installation space were evaluated. The three technically feasible control options for the CELP facility were determined to be HAR, SDA, and DSI.

The ability of the existing fabric filter baghouses at CELP to accommodate additional particulate resulting from HAR, SDA or DSI is in question based on prior conversations with a vendor of these systems. The vendor previously indicated that the baghouse design must be matched with the add-on control systems and its resulting particulate loading. Therefore, the existing baghouse system would need to be replaced or potentially redesigned significantly to accommodate the increase in particulate in the flue gas stream. As a result, we have included a redesigned (new) fabric filter baghouse in the cost for each SO_2 control technology. The costs of these feasible technologies will be discussed in Section 5.3.

5.2 NO_x Control Measures

Applicable NO_x control technologies can be divided into two main categories: combustion controls, which limit NO_x production, and post-combustion controls, which destroy NO_X after formation.

CELP currently controls NO_x emissions using good combustion practices in the CFBC boilers.[15] Emissions are controlled through the boiler design and its lower operating temperatures, and a recirculation of fuel and ash particles through the combustion boiler. The lower operating temperature in a CFBC boiler already reduces the formation of thermal NO_x emissions in the range of 50% or more compared to other boiler designs. CELP must meet NO_x emission limits of 328.0 pounds per hour, 7,864 pounds per day, and 1,435 tons per year per #OP2035-03. CELP demonstrates compliance with these limits using continuous emission monitors and EPA Method 7.

5.2.1 NO_x Control Technologies Considered

As CELP is currently using boiler design to control NOx emissions, only post-combustion controls were considered for this analysis. The post-combustion controls that are initially technically feasible in this application are Low Excess Air (LEA), Flue Gas Recirculation (FGR), Overfire Air (OFA), Low NO_x Burners (LNB), Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction.

<u>Low Excess Air</u>

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_x and lowers the peak flame temperature, which inhibits thermal NO_x formation.

Emissions reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons and unburned carbon increase, resulting in lower boiler efficiency. Other impediments to LEA operation are the possibility of increased corrosion and slagging in the upper boiler because of the reducing atmosphere created at low oxygen levels.

This technology is typically utilized on Pulverized Coal (PC)-fired units. This option cannot be utilized on CFBC due to air needed to fluidize the bed.

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[15] CFBC technology design has inherently lower combustion temperatures than pulverized coal (PC) technology. The lower combustion temperature of a CFBC boiler (1550 – 1650ºF) typically leads to a lower formation of thermal NOx than a PC boiler, which has a relatively higher combustion temperature (2400 – 2700ºF) and more thermal NOx.

Flue Gas Recirculation

FGR is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. FGR also serves to reduce the O_2 concentration in the combustion zone.

This technology is typically utilized on PC-fired units. This option cannot be utilized on CFBC due to air needed to fluidize the bed.

Overfire Air

OFA allows staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners. The remaining necessary combustion air is injected into the furnace through overfire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of fuel NO_X. In this atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Having combustion occur over a larger portion of the furnace lowers peak flame temperatures. Use of a cooler, less intense flame limits thermal NO_X formation.

Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the fly ash. These products of incomplete combustion result from a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion of the boiler.

This technology is typically utilized on PC units. This option cannot be utilized on CFBC due to air needed to fluidize the bed.

Low NO_X Burners

LNB integrate staged combustion into the burner creating a fuel-rich primary combustion zone. Fuel NO_x formation is decreased by the reducing conditions in the primary combustion zone. Thermal NO_x is limited due to the lower flame temperature caused by the lower oxygen concentration. The secondary combustion zone is a fuel-lean zone where combustion is completed. LNB may result in increased CO and hydrocarbon emissions, decreased boiler efficiency, and increased fuel costs.

This technology is typically utilized on PC units. This option cannot be utilized on CFBC because the combustion occurs within the fluidized bed.

Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique that uses a catalyst to reduce NO and NO_2 to molecular nitrogen, water, and oxygen. Ammonia (NH_3) is commonly used as the reducing agent.

Ammonia is vaporized and injected into the flue gas upstream of the catalyst bed and combines with NO_X at the catalyst surface to form an ammonium salt intermediate. The ammonium salt intermediate then decomposes to produce elemental nitrogen and water. The catalyst lowers the temperature required for the chemical reaction between NO_X and ammonia.

Technical factors that impact the effectiveness of this technology include the catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, and the potential for catalyst poisoning.

SCR has been demonstrated to achieve high levels of NO_x reduction in the range of 80% to 90% control for a wide range of industrial combustion sources, including PC and stoker coal-fired boilers and natural gas-fired boilers and turbines. Typically, installation of the SCR is upstream of the particulate control device (e.g., baghouse). However, calcium oxide (from a dry scrubber) in the exhaust stream can cause the SCR catalyst to plug and foul, which would lead to an ineffective catalyst.

SCRs are classified as a low or high dust SCR. A low dust SCR is usually applied to natural gas combustion units or after a particulate control device. High dust SCR units can be installed on solid fuel combustion units before the particulate control device, but they have their limitations.

Selective Non-Catalytic Reduction

SNCR involves the non-catalytic decomposition of NO_x to nitrogen and water. An NO_x reducing agent, typically ammonia or urea, is injected into the upper reaches of the furnace. Because a catalyst is not used to drive the reaction, temperatures of 1600 to 2100°F are required.

Typical NOx control efficiencies range from 40% – 60%. NO_X removal efficiency varies for this technology, depending on inlet NO_X concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and presence of interfering chemical substances in the gas stream.

5.2.2 Eliminating Technically Infeasible Options

Because OFA, LEA, and FGR are used to reduce flame temperature and reduce the thermal NO_x, these control options are technically ineffective on a CFBC boiler that has inherently low combustion temperatures and relatively lower thermal NO_x. Further, a CFBC boiler does not use burners like a PC boiler, limiting the available combustion control options. The remaining post-combustion NO_x control options are considered technically feasible.

5.2.3 Identify Technically Feasible Options

SCR and SNCR are considered technically feasible options for NO_x control of the CELP boiler for the purpose of this analysis. However, both control technologies have difficulties in design, construction, and implementation. The CELP facility has a limited area to install additional controls and manage waste materials as mentioned in Section 5.1.2. These space limitations also apply to the potential installation of SCR and SNCR. Both control technologies are continuing to be evaluated; however, these technical limitations are described further in the energy and non-air environmental compliance section (Factor 3) and the summary.

An in-depth description of each control system is detailed in the following sections.

5.2.3.1 SCR

Theoretically, SCR systems can be designed for NO_x removal efficiencies close to 100 percent. In practice, <u>new</u> commercial coal-, oil-, and natural gas-fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NO_x controls such as LNB or FGR that achieve relatively low emissions on their own (including CFBC boiler technology). The outlet concentration from SCR on a utility boiler is rarely less than 0.04 pounds per MMBtu (lb/MMBtu) [12,13].[16] Based on that limitation, which is particularly applicable to a retrofit unit, the proposed reduction associated with SCR for the CELP Boiler is 80% as provided by vendor data detailed in Factor 1.

With respect to reagents, either ammonia or urea may be used as the NO_x reduction reagent in SCR systems. Urea is generally converted to ammonia before injection. Results of a survey of electric utilities that operate SCR systems indicated 80 percent use ammonia (anhydrous and aqueous), and the remainder use urea [13]. Additionally, a survey of coal-fired power plants that control NO_x emissions using either SCR or SNCR found anhydrous ammonia use exceeds aqueous ammonia use by a ratio of 3 to 1 [13]. Nearly half of these survey respondents indicated that price is their primary consideration in the choice of reagent with safety second. Because ammonia is most commonly used and was provided in the vendor quote, it was used in the reagent calculations for the CELP Boiler [14].

Ammonia or urea is injected into the flue gas upstream of a catalyst bed, and NO_X and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction. Typical catalyst materials include metal oxides (e.g., titanium oxide and vanadium), noble metals (e.g., platinum and rhodium), zeolite, and ceramics.

[16] Data in the Clean Air Markets Division (CAMD) database also suggest SCR units rarely achieve emissions less than 0.04 lb/MMBtu.

The control technology works best for flue gas temperatures between 575°F and 750°F. Excess air is injected at the boiler exhaust to reduce temperatures to the optimum range, or the SCR is located in a section of the boiler exhaust ducting where the exhaust temperature has cooled to this temperature range. Technical factors that impact the effectiveness of this technology include inlet NO_x concentrations, the catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning.

In retrofit installations, new ductwork would be required to integrate the SCR system with the existing equipment. In low-dust SCR systems for utility and industrial boilers, the SCR reactor would be located between the outlet duct of the particulate control device and the air heater inlet duct.

Retrofit of SCR on an existing unit has higher capital costs than SCR installed on a new system. There is a wide range of SCR retrofit costs due to site-specific factors, scope differences, and site congestion [15]. Specific factors that impact the retrofit costs include the following [13]:

- Amount of available space between and around the economizer and air heater;
- Congestion downstream of the air heater (i.e., buildings, conveyors, existing particulate control, flue gas desulfurization (FGD) system, induced draught (ID) fan, or stack);
- Age/vintage and manufacturer of the boiler;
- Design margin of the existing ID fan (i.e., the need to upgrade or replace fan impellers, replace ID fans, or add booster fans);
- Capacity, condition, and design margins of the electrical distribution system;
- Design margins of the existing structural steel support systems;
- The positive and negative design pressure of the furnace and existing particulate control; and
- Number, nature, and type of existing items that must be relocated to accommodate the SCR and associated systems.

5.2.3.2 SNCR

Per the April 2019 update of the EPA Cost Control Manual [16], SNCR is a post-combustion emissions control technology for reducing NO_x by injecting an ammonia type reactant into the furnace at a properly determined location. This technology is often used for mitigating NO_x emissions since it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. The conventional SNCR process occurs within the combustion unit, which acts as the combustion chamber.

SNCR involves the noncatalytic decomposition of NO_X in the flue gas to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,550°F and 1,950°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_x emissions may result.

The process has been used in North America since the early 1980s and is most common on utility boilers, specifically coal-fired utility boilers. Removal efficiencies of NO_X vary considerably for this technology, depending on inlet NO_X concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip and the presence of interfering chemical substances in the gas stream.

Reagent costs currently account for a large portion of the annual operating expenses associated with this technology, and this portion has been growing over time. Ammonia is generally less expensive than urea because urea is derived from ammonia. However, the choice of reagent is based not only on cost but also on physical properties and operational considerations. Ammonia was employed as the reagent in the CELP SNCR cost analysis because it was determined to be the most appropriate reagent by the vendors and was included in the vendor quote. An average reduction of 50% was used in the cost efficiency calculations because that was selected/determined to be feasible in the vendor quote.

For SNCR retrofit of existing boilers, optimal locations for injectors may be occupied with existing boiler equipment such as the watertubes. The primary concern is adequate wall space within the boiler for installation of injectors. The injectors are installed in the upper regions of the boiler, the boiler radiant cavity, and the convective cavity. Existing watertubes and asbestos may need to be moved or removed from the boiler housing. In addition, adequate space adjacent to the boiler must be available for the distribution system equipment and for performing maintenance. This may require modification or relocation of other boiler equipment, such as ductwork. The estimated costs on a $/kW basis increase sharply for small boilers (<50 MW) due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers. The CELP boiler is nominally rated at 43 MW and is considered a small boiler.

5.3 Factor 1 – Cost of Compliance

The cost of compliance estimates the capital cost of purchasing and installing new control equipment along with the annual operation and maintenance (O&M) cost as generally outlined in EPA Draft Guidance. These categories of costs include categories such as direct capital cost, indirect capital cost, labor cost, contingency cost, and annual cost. Methodologies given in the EPA Air Pollution Control Cost Manual (Control Cost Manual) are the indicated reference for determining the cost of compliance for SNCR and SCR [17].

Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of actual emissions reduced by the proposed control option. Baseline emissions for the CFBC Boiler were taken from the baseline emission rate agreed to by MDEQ of the 2014 – 2016 average annual emissions.

The capital recovery factor was applied to the control options based on a 20-year equipment life expectancy and applying the 5.5% as the interest rate noted by MDEQ in their April 19, 2019, email correspondence. The resulting cost of compliance is presented in Tables 2 and 3. Details of the calculations may be found in Appendix B.

5.3.1 SO_2 Cost Effectiveness

The cost-effectiveness of each of the technically feasible SO_2 control technologies was estimated based on the methodologies developed by William M. Vatavuk in the book "Estimating Costs of Air Pollution Control" [18] and the methodologies provided in EPA's Office of Air Quality Planning and Standards (OAQPS) Pollution Cost Control Manual, 6th Edition [19]. Each cost analysis is based on the methodology described in Cost Control Manual Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal. The cost effectiveness was estimated using the OAQPS example for Acid Gas Removal because it most closely reflected the control methods being assessed when compared to the other OAQPS choices. This same methodology was utilized in the Round 1 analysis.

Equipment and system operations have remained the same at CELP since the Round 1 analysis was accepted by the EPA in 2011. Therefore, the Round 1 cost analysis has been updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019 dollar values due to inflation.[17]

The average of CELP SO_2 emissions from 2014 to 2016 was used to estimate the cost-effectiveness of the technically feasible control options. The results of the analysis are summarized in *Table 2*. Detailed calculations and supporting information are provided in *Appendix B* – Cost Analysis. All three control options include the cost of installing the designated control option as well as the corresponding, upgraded baghouse system.

[17] Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

Table 2: Estimated Costs of SO_2 Control Options for CELP

SO_2 Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost-Effectiveness ($/ton)
CFBC with Hydrated Ash Reinjection and Baghouses	50%	**$22,177,580**	**$3,669,038**	**616**	**616**	**$5,961**
CFBC with Spray Dry Absorbers and Baghouses	80%	**$28,435,354**	**$4,814,409**	**985**	**246**	**$4,889**
CFBC with DSI and Baghouses	50%	**$13,994,337**	**$2,848,330**	**616**	**616**	**$4,628**

The costs for additional control of the boilers are prohibitive. Initial discussions with MDEQ indicated "Best Available Control Technology (BACT) level" costs would be considered for the four-factor analysis process. As previously discussed, the calculated costs above incorporate the additional cost of an upgraded baghouse system. These costs exceed BACT level cost per ton values at recently permitted units.

5.3.2 NO_2 Cost-Effectiveness

During the Round 1 analysis, CELP consulted with Bison, the Harris Group, and Metso to estimate the cost-effectiveness of installing SCR or SNCR at the facility. Metso and the Harris Group have extensive experience building CFBCs with NO_x controls. Their expertise was utilized to develop as close to an estimate of each control technology as possible.

The cost-effectiveness of the technically feasible NO_x control technologies was estimated using the Round 1 total capital and operating cost estimates developed by Metso, the Harris Group, and by the Office of Air Quality Planning and Standards (OAQPS) Pollution Cost Control Manual, 6th Edition [19]. The Metso and Harris Group cost estimates were provided specifically for the CELP facility and provide the most reasonable estimate for this stage of planning. Therefore, the 2011 analyses were revised utilizing the vendor-specific cost estimates. The equipment and system operations have remained the same at CELP since the Round 1 analysis was accepted by the EPA in 2011. The Round 1 cost analysis for NO_x has also been updated for this cost of compliance demonstration by revising the calculation parameters to account for a 20-year life expectancy, 5.5% interest rate, and adjusting 2011 prices to 2019 dollar values due to inflation. Facility-specific vendor costs are assumed to be more accurate than generic facility calculations from EPA's Cost Control Manual.

The average of CELP NO_2 emissions from 2014 to 2016 was used to estimate the cost-effectiveness of the technically feasible control options. The results of the analysis are summarized in *Table 3*. Detailed calculations and supporting information are provided in *Appendix B* – Cost Analysis. Both control options include the cost of installing the designated control option but do not account for the cost of facility downtime.

Table 3: Estimated Costs of NO_2 Control Options for CELP

NOx Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost-Effectiveness ($/ton)
CFBC with Selective Catalytic Reduction	80%	**$15,650,550**	**$2,269,256**	**714**	**178**	**$3,179**
CFBC with Selective Non-Catalytic Reduction	50%	**$1,020,800**	**$601,808**	**202**	**202**	**$1,527**

The costs for additional NO_x control of the boiler varies and is difficult to accurately estimate at a preliminary design stage. Due to space limitations causing constraints in design capabilities, these proposed costs are an initial estimate for installing the add-on control systems with limited knowledge of the CELP network equipment (i.e., plant piping, cable piping, etc.). As noted in the Metso report, this is an order of magnitude estimate because there could be interferences and significant unknowns that would alter Metso's cost estimates. Additional capital investment would be required from CELP to determine a more refined cost estimate.

Additionally, the vendor cost estimates do not account for lost revenue due to facility downtime. The time necessary for compliance is detailed in Factor 2. Lost revenue due to facility downtime would increase the total annual costs associated with adding on emissions controls. Additionally, CELP's contractual obligations with NorthWestern Energy (NorthWestern) and difficulty in the ability to secure financing are discussed in the report's conclusion section.

5.4 Factor 2 – Time Necessary for Compliance

The following subsections will discuss the estimated amount of time to install the SO_2 and NO_x control technologies identified previously in this report.

5.4.1 Installation of SO_2 Controls

The addition of HAR, SDA, and DSI would each take approximately the same amount of time. As stated previously, the addition of SO_2 controls would likely require complete replacement or major modifications to the existing baghouse. Bison estimates that the time necessary to complete the modifications to the boiler would be approximately four to six months. A boiler outage of approximately two to three months would be necessary to perform the installation of both control systems.

5.4.2 Installation of NOx Controls

Due to the complexity of the existing infrastructure and limited space, the installation of SCR is estimated to take approximately 26 months. The installation of SNCR is less complex and would take approximately 24-30 weeks. Please see the attached vendor report included in *Appendix B* for more information.

5.5 Factor 3 – Energy and Non-air Environmental Impacts

5.5.1 Energy Impacts: SO_2 Controls

FGD systems require electricity to operate. The dry FGD uses electricity primarily for the ID fan, lime/limestone handling equipment and baghouse blowers. SDA, DSI, and HAR systems have been estimated to consume 0.1% to 0.5% of total plant generation.

5.5.2 Energy Impacts: NO_x Controls

The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility. On the other hand, SCR would cause a significant backpressure in the CFBC boiler leading to lost boiler efficiency and a loss of power production. Along with the power loss, CELP would be subject to the additional cost of reheating the exhaust gas, which is an inefficient use of energy and would incur additional fuel costs.

5.5.3 Non-Air Quality Impacts: SO_2 controls

The addition of the SO_2 controls would result in increased ash production at the CELP facility. Boiler ash is currently either sent to a landfill or sold for beneficial use, such as oil well reclamation. Changes in ash properties due to increased calcium sulfates and calcium sulfites could result in the ash being no longer suitable to be sold for beneficial uses. The loss of this market would cost REC approximately $1,020,000 year at the current ash value and production rates (approximately 100,000 tons of ash/year). The loss of this market would also result in REC having to dispose of the ash at its current landfill, which is adjacent to the plant. If CELP had to dispose of the unsalable ash, the increased cost would be approximately $62,000/year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $1,082,000/year.

5.5.4 Non-Air Quality Impacts: NOx Controls

The addition of chemical reagents in SNCR and SCR controls would add equipment for its storage and use. The storage of on-site ammonia would pose a risk from potential releases to the environment. An additional concern is the loss of ammonia, or “slip” into the emissions stream from the facility; this “slip” contributes another pollutant to the environment, which has been implicated as a precursor to fine particulate formation in the atmosphere. The additional costs of chemicals and catalysts have been included in the cost analysis.

SCRs can contribute to airheater fouling due to ammonia bisulfate formation. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, and cause corrosion and erosion.

On some installations, catalyst life is very short and SCRs have fouled in high dust environments. This had led to boiler downtime in some installations. A detailed assessment of catalyst life cost would require further analysis by a catalyst vendor.

5.6 Factor 4 – Remaining Useful Life of Source

The CFBC Boiler at CELP is not planned for retirement at this time. As dictated in discussions and correspondence with MDEQ, the remaining useful life of the sources is assumed to be 20 years.

6.0 CONCLUSIONS

A four-factor analysis was conducted for the CELP facility to meet the requirements of Round 2 of the RHR in order to develop an SIP addressing Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, MDEQ requested this analysis from CELP.

The four factors analyzed were based on MDEQ correspondence and the RHR to determine if there are emission control options at CELP that, if implemented, could be used to attain reasonable progress toward the state's visibility goals. The factors reviewed included the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and the remaining useful life of the existing source subject to these requirements.

The four-factor analysis was conducted for SO_2 and NO_x on the CFBC boiler at CELP with additional discussion regarding facility-wide and regional emissions reduction efforts. As previously mentioned, Colstrip Units 1 and 2 are scheduled for shutdown later in 2019. That shutdown will remove emissions from the Colstrip airshed by an order of magnitude greater than the CELP facility's emissions. The impending emissions decrease in the area as well as the lack of correlation between CELP emissions and visibility in nearby Class I areas demonstrate reasonable progress is already being made in the Colstrip area.

As requested by EPA, REC has analyzed its CFBC boiler at the CELP facility for the purposes of meeting the Reasonable Progress Goals of the Regional Haze Rule. REC retained Metso, the Harris Group, and Bison to assist REC in evaluating possible control alternatives at CELP. The analysis identified two technically feasible controls for NOx (SCR and SNCR) and three technically feasible controls for SO_2 (HAR, SDA, and DSI).

As part of the analysis, EPA requested that CELP analyze the costs of compliance. The EPA's document "Guidance for Setting Reasonable Progress Goals under the Regional Haze Program"[18] states:

> "…the cost of compliance factor can be interpreted to encompass the cost of compliance for individual sources or source categories, and more broadly the implication of compliance to the health and vitality of industries within a state."

The two technically feasible NO_x control options identified in the Metso study would have major impacts on the facility and its ability to continue in operation. To put this discussion in context, CELP has a long-term fixed rate contract through 2024 with NorthWestern to

[18] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. Environmental Protection Agency Office of Air Quality Planning and Standards Air Quality: http://www.epa.gov/ttncaaa1/t1/memoranda/reasonable_progress_guid071307.pdf.

sell its electrical output. That contract determines the rates to be paid, and does not allow any pass-through of any costs, whether capital, operating, financing, or otherwise. To the extent it can do so, the entire burden (including lost revenue, as well as all other impacts) of implementation of any required control method will be borne by the CELP facility. The CELP facility provides many benefits to the state and community, through direct employment, utilization of vendors' goods and services, and taxes.

As can be seen in this response and the attachments hereto, the two NO_x control options (SCR and SNCR) bring with them capital and installation costs of $15,650,000 and $927,000, and annual operating costs of $2,270,000 and $680,000, respectively. These operating costs would triple in the SCR case, or be five times greater in the SNCR case, than CELP's current budgeted costs for similar requirements. They also have the potential to cost the project on the order of $1,000,000 annually in lost revenue and incurred disposal costs for ash presently sold and, in the case of SCR, include an extraordinary downtime of two to three months for implementation, resulting in a loss of revenue which is neither insured nor passed through to NorthWestern.

The addition of SO_2 controls would have a similar impact on CELP’s ability to remain in operation. Bison identified three technically feasible SO_2 controls, which are hydrated ash re-injection (capital investment $22,180,000 - annual operating cost $3,700,000), spray dry absorber (capital investment $28,400,000 - annual operating cost $4,800,000), and dry sorbent injection (capital investment $14,000,000 - annual operating cost $2,850,000), also bringing with them lost revenue and increased costs for ash disposal, and boiler downtime of two to four months to modify CELP's boiler.

CELP has no capacity for further borrowing to implement the costs of any of the alternatives (SO_2 or NO_x), either for capital improvements, installation, or operations. Just the downtime alone for implementation of the SCR alternative or any of the SO_2 alternatives would cause CELP to be unable to meet ongoing operating cost obligations. CELP is financed by tax exempt bonds issued by the State of Montana. Should CELP be required to implement either alternative without a cost pass-through mechanism to the purchaser of its output, the outcome would be bankruptcy for CELP. The consequences to the community and state of such an event would be annual loss of about $14,000,000 in payroll, vendor payments, property taxes, etc., and default on about $37,000,000 in debt-related obligations.

With respect to the purpose of this analysis, the RHR [§308(d)] outlines what it refers to as: “the core requirements” for the implementation of the regional haze goals. More specifically, §308(d)(1) states:

> “*For each mandatory Class I Federal area . . ., the State must establish goals . . . that provide for reasonable progress towards achieving natural visibility conditions.* ***The reasonable progress goals must provide for an improvement in visibility*** *for the most impaired days...”* [40 CFR 51.308(d)(1)].

Reasonable progress is tied to an improvement in visibility, not costly pollution control without benefit. The results of the analysis have indicated that additional controls on the CFBC Boiler are not necessary to make reasonable progress due to costs and CELP's lack of a measurable impact on any nearby Class I area, particularly in light of recent emissions reductions by other regional and state facilities. It is concluded that this facility does not qualify for additional emission controls or limitations based on this analysis.

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APPENDIX A: CORRELATION ANALYSES

Visibility and NOx Correlation Calculations

UL Bend Wilderness Area

		Anthro dV	*All dV*	*Glidepath*	*Anthro NO3*	*CELP NOx*	*Colstrip NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Glidepath	0.74	0.07	1			
	Anthro NO3	0.77	0.23	0.45	1		
	CELP NOx	0.14	0.04	0.19	0.35	1	
	Colstrip NOx	0.67	0.19	0.92	0.43	0.40	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Glidepath	0.55	0.00	1			
	Anthro NO3	0.59	0.05	0.20	1		
	CELP NOx	0.02	0.00	0.04	0.12	1	
	Colstrip NOx	0.45	0.04	0.85	0.18	0.16	1

Visibility and NOx Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Glidepath*	*Anthro NO3*	*CELP NOx*	*Colstrip NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.75	1				
	Glidepath	0.79	0.62	1			
	Anthro NO3	0.89	0.70	0.62	1		
	CELP NOx	0.18	0.21	0.20	0.36	1	
	Colstrip NOx	0.57	-0.27	0.89	0.41	0.40	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.57	1				
	Glidepath	0.62	0.38	1			
	Anthro NO3	0.79	0.49	0.38	1		
	CELP NOx	0.03	0.04	0.04	0.13	1	
	Colstrip NOx	0.32	0.07	0.79	0.17	0.16	1

Visibility and NOx Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Glidepath*	*Anthro NO3*	*CELP NOx*	*Colstrip NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Glidepath	0.80	-0.11	1			
	Anthro NO3	0.53	-0.40	0.76	1		
	CELP NOx	0.02	-0.40	0.20	0.04	1	
	Colstrip NOx	0.76	-0.16	0.89	0.70	0.40	1

		Anthro dV	All dV	Glidepath	Anthro NO3	CELP NOx	Colstrip NOx
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Glidepath	0.64	0.01	1			
	Anthro NO3	0.28	0.16	0.57	1		
	CELP NOx	0.00	0.16	0.04	0.00	1	
	Colstrip NOx	0.58	0.03	0.79	0.49	0.16	1

Visibility and NOx Correlation Calculations

Yellowstone National Park

		Anthro dV	*All dV*	*Glidepath*	*Anthro NO3*	*CELP NOx*	*Colstrip NOx*
r =	Year						
	Anthro dV	1					
	All dV	0.45	1				
	Glidepath	0.48	-0.25	1			
	Anthro NO3	0.37	-0.07	0.57	1		
	CELP NOx	0.03	-0.52	0.20	0.03	1	
	Colstrip NOx	0.57	-0.27	0.89	0.41	0.40	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.20	1				
	Glidepath	0.23	0.06	1			
	Anthro NO3	0.14	0.01	0.32	1		
	CELP NOx	0.00	0.27	0.04	0.00	1	
	Colstrip NOx	0.32	0.07	0.79	0.17	0.16	1

Visibility and NOx Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Glidepath*	*Anthro NO3*	*CELP NOx*	*Colstrip NOx*
r =	Year						
	Anthro dV	1					
	All dV	-0.09	1				
	Glidepath	0.82	-0.29	1			
	Anthro NO3	0.78	-0.11	0.84	1		
	CELP NOx	0.41	-0.15	0.20	0.30	1	
	Colstrip NOx	0.83	-0.11	0.88	0.91	0.40	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.01	1				
	Glidepath	0.68	0.08	1			
	NO3	0.61	0.01	0.71	1		
	CELP NOx	0.17	0.02	0.04	0.09	1	
	Colstrip NOx	0.69	0.01	0.77	0.83	0.16	1

Visibility and SO_2 Correlation Calculations

UL Bend Wilderness Area

		Anthro dV	*All dV*	*Glidepath*	*Anthro SO_4*	*CELP SO_2*	*Colstrip SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Glidepath	0.74	0.07	1			
	Anthro SO_4	0.70	-0.08	0.51	1		
	CELP SO2	-0.11	-0.07	0.06	-0.28	1	
	Colstrip SO_2	0.83	0.06	0.89	0.60		1
r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Glidepath	0.55	0.00	1			
	Anthro SO_4	0.49	0.01	0.26	1		
	CELP SO_2	0.01	0.00	0.00	0.08	1	
	Colstrip SO_2	0.69	0.00	0.79	0.36	0.00	1

Visibility and SO_2 Correlation Calculations

Theodore Roosevelt National Park

		Anthro dV	*All dV*	*Glidepath*	*Anthro SO_4*	*CELP SO_2*	*Colstrip SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.75	1				
	Glidepath	0.79	0.62	1			
	Anthro SO_4	0.88	0.61	0.63	1		
	CELP SO_2	0.02	0.04	0.06	-0.20	1	
	Colstrip SO_2	0.91	0.65	0.89	0.82	0.06	1
r2 =	Year						
	Anthro dV	1					
	All dV	0.57	1				
	Glidepath	0.62	0.38	1			
	Anthro SO_4	0.77	0.37	0.40	1		
	CELP SO_2	0.00	0.00	0.00	0.04	1	
	Colstrip SO_2	0.83	0.42	0.79	0.67	0.00	1

Visibility and SO_2 Correlation Calculations

North Absaroka Wilderness Area

		Anthro dV	*All dV*	*Glidepath*	*Anthro SO_4*	*CELP SO_2*	*Colstrip SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.26	1				
	Glidepath	0.80	-0.11	1			
	Anthro SO_4	0.62	-0.25	0.83	1		
	CELP SO_2	-0.14	-0.18	0.06	-0.06	1	
	Colstrip SO_2	0.73	-0.27	0.89	0.87	0.06	1

r2 =	Year						
	Anthro dV	1					
	All dV	0.07	1				
	Glidepath	0.64	0.01	1			
	Anthro SO_4	0.39	0.06	0.69	1		
	CELP SO_2	0.02	0.03	0.00	0.00	1	
	Colstrip SO_2	0.53	0.07	0.79	0.76	0.00	1

Visibility and SO_2 Correlation Calculations

Yellowstone National Park

		Anthro dV	*All dV*	*Glidepath*	*Anthro SO_4*	*CELP SO_2*	*Colstrip SO_2*
r =	Year						
	Anthro dV	1					
	All dV	0.45	1				
	Glidepath	0.48	-0.25	1			
	Anthro SO_4	0.47	-0.13	0.66	1		
	CELP SO_2	0.02	-0.29	0.06	0.31	1	
	Colstrip SO_2	0.23	-0.35	0.89	0.63	0.06	1

		Anthro dV	*All dV*	*Glidepath*	*Anthro SO_4*	*CELP SO_2*	*Colstrip SO_2*
r2 =	Year						
	Anthro dV	1					
	All dV	0.20	1				
	Glidepath	0.23	0.06	1			
	Anthro SO_4	0.22	0.02	0.44	1		
	CELP SO_2	0.00	0.08	0.00	0.10	1	
	Colstrip SO_2	0.05	0.12	0.79	0.40	0.00	1

Visibility and SO_2 Correlation Calculations

Gates of the Mountains Wilderness Area

		Anthro dV	*All dV*	*Glidepath*	*Anthro SO_4*	*CELP SO_2*	*Colstrip SO_2*
r =	Year						
	Anthro dV	1					
	All dV	-0.09	1				
	Glidepath	0.82	-0.29	1			
	Anthro SO_4	0.69	-0.37	0.90	1		
	CELP SO_2	0.20	-0.42	0.06	0.12	1	
	Colstrip SO_2	0.77	-0.31	0.88	0.88		1

		Anthro dV	*All dV*	*Glidepath*	*Anthro SO_4*	*CELP SO_2*	*Colstrip SO_2*
r2 =	Year						
	Anthro dV	1					
	All dV	0.01	1				
	Glidepath	0.68	0.08	1			
	Anthro SO_4	0.48	0.14	0.81	1		
	CELP SO_2	0.04	0.18	0.00	0.01	1	
	Colstrip SO_2	0.59	0.10	0.77	0.77	0.00	1

APPENDIX B: COST ANALYSIS

CELP

Nox Control Cost Summary

NOx Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
CFB with Selective Catalytic Reduction	80%	**$15,650,550**	**$2,269,256**	**714**	**178**	**$ 3,178.94**
CFB with Selective Non-Catalytic Reduction	50%	**$927,440**	**$681,195**	**446**	**446**	**$ 1,526.83**

Emissions (2014 - 2016) 892.3 **NO_2 tpy**

CELP Nox Control Cost Analysis
SCR Cost Effectiveness Estimation Based on Contractor Estimates

Based on contractor estimates developed by Metso, Inc. and Harris Group, Inc. See attached report.

Cost Item	Cost: 2019 Inflation Adjustment[a]	Cost: 2011 Analysis	Reference
Total Capital Investment			
Metso estimate	$15,650,550	*$13,500,000*	Metso (Vendor Estimate)
Direct Annual Costs			
Ammonia System Maintenance =	$11,593	*$10,000*	Contractor Estimate
Soot Blower Maintenance =	$5,797	*$5,000*	Contractor Estimate
Additional Pressure Drop =	$99,353	*$85,701*	Contractor Estimate
ARC =	$332,763 /yr	*$287,038 /yr*	Reagent consumption cost
ACRC =	$288,492 /yr	*$248,850 /yr*	SCR catalyst
	$175,286 /yr	*$151,200 /yr*	Catalyst install
	$46,372 /yr	*$40,000 /yr*	SCR disposal
DAC =	$959,656 /yr		Direct annual costs
Indirect Annual Costs			
CRF =	$i / (1 - (1 + i)^{-n})$		
i=	*5.5%*		
n=	*20*		
=	0.084		Capital recovery factor
	*CRF * TCI*		
IDAC =	$1,309,600 /yr		Indirect annual costs
Total Annual Costs			
TAC =	$2,269,256		Total annual cost
Tons of Nox, uncontrolled:			
Tons Nox emitted/year	*892.30*	tons	Average of 2014 - 2017 NOx tons as provided by MDEQ
NOx (lbs/hr):	204	lbs/hr	
Tons of Nox, controlled:			
η_{NOX} =	80%	Control efficiency	
NOx (lbs/hr):	40.74	lbs/hr	
Tons Nox emitted/year	178.5	tons	
Tons Nox reduced/year	713.84	tons	
Cost Effectiveness ($/ton)	**$ 3,178.94**		

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

CELP Nox Control Cost Analysis
SNCR Cost Effectiveness Estimation Based on Contractor Estimates

Based on contractor estimates developed by Metso, Inc. See attached report.

Also based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 4.2, Chapter 1

Input Values				Description	Reference
	Q_B =	550.0	MMBtu/hr	Heat input rate	Operation Data
	η_{NOX} =	0.5	Control efficiency	SNCR Nox Control Efficiency	Bison Estimate
	$NO_{X,IN}$ =	0.400	lb/MMBtu	Inlet NOx factor	Annual Emission Inventories
	CF_{PLANT} =	0.92		Capacity factor of plant	Average of 2008 and 2009 Operations
	CF_{SCR} =	1.0		Capacity factor of SNCR when plant is operational	Bison Estimate
	$Cost_{ELEC}$ =	0.06	$/kWh	Cost of electricity	Bison Estimate
	i =	5.5%		Interest rate, assumed	Bison Estimate
				SRT is 1 for ammonia and 2 for urea	
Design Values					
	CF_{TOTAL} =	$CF_{PLANT} * CF_{SCR}$			Reference 1, Eqn 1.7
	=	0.92		(Capacity Factor)	
	NSR =	$[2 * NOx_{IN} + 0.7]\ \eta_{NOx} / NOx_{IN}$			Reference 1, Figure 1.8
	=	3.00		(Normalized Stoichiometric Ratio)	*(Value read from chart)*
	Power =	$0.47 * NOx_{IN} * NSR * Q_B / 9.5$			Reference 1, Eqn 1.23
	=	32.65	kw	(Power Consumption Rate)	

SNCR Cost Effectiveness
Continued.

Cost Item	Cost: 2019 Inflation Adjustment[a]		Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Total Capital Investment				
Metso estimate	$927,440	Total capital investment, Contractor Esti	**$927,440**	*$800,000*
(adjusted for inflation)				
Direct Annual Costs				
Ammonia System Maintenance =	$17,390		**$17,390**	*$15,000*
(adjusted for inflation)				
ARC =	$554,606 /yr	Annual Reagent Cost, Contractor Estima	**$554,606 /yr**	*$478,397 /yr*
(adjusted for inflation)				
PWR =	$[0.47 * Q_B * NO_{X,IN} * NSR] / 9.5$			
=	65.3 kW	Power usage rate for both systems		
PC =	$PWR * CF_{TOTAL} * 8760 * COST_{ELEC}$			
=	$31,600			
DAC =	$AMC + ARC + PC + AWC$			
	$603,595 /yr			
Indirect Annual Costs				
CRF =	$i / (1 - (1 + i)^{-n})$			
i=	*5.5%*			
n =	20.0			
CRF =	0.084	Capital recovery factor		
IDAC =	$CRF * TCI$			
=	$77,600 /yr	Indirect annual costs		

SNCR Cost Effectiveness
Continued.

Cost Item	Cost: 2019 Inflation Adjustment[a]			Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Total Annual Costs					
TAC =	*DAC + IDAC*				
TAC =	$681,195		Total annual cost		
Tons of Nox, uncontrolled:					
NOx (lbs/hr):	204	lbs/hr			
Tons Nox emitted/year	*892.30*	tons	Average of 2014 - 2017 NOx tons as provided by MDEQ		
Tons of Nox, controlled:					
η_{NOX} =	50%	Control efficiency			
NOx (lbs/hr):	101.86	lbs/hr			
Tons Nox emitted/year	446.2	tons			
Tons Nox reduced/year	446.2	tons			
Cost Effectiveness ($/ton)	**$ 1,526.83**				

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019.
https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

CELP

SOx Cost Summary

SO_2 Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
CFB with Hydrated Ash Reinjection and Baghouses	50%	**$22,177,580**	**$3,109,485**	**616**	**616**	**$5,052**
CFB with Spray Dry Absorbers and Baghouses	80%	**$28,435,354**	**$4,254,856**	**985**	**246**	**$4,321**
CFB with DSI and Baghouses	50%	**$13,994,337**	**$2,288,776**	**616**	**616**	**$3,719**

Emissions (2014 - 2016) 1231 **SO2 (tpy)**

CELP

SO2 Cost Analysis

Cost for Hydrated Ash Reinjection

Estimated using OAQPS example for Acid Gas Removal

Based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal

Cost Item	Factor	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT COSTS			
Purchased equipment costs			
Number of hydrated ash systems required:		1	
Plant mW, per boiler (Gross)		43	
Cost per system + auxiliary equipment (Bison Estimate)[b]:		$ 5,317,322.67	*$4,586,667*
Total FDA + auxiliary equipment	A	$5,317,322.67	
Instrumentation	0.10 A	$531,732	
Sales taxes	0.03 A	$159,519.68	
Freight	0.05 A	$265,866	
Purchased equipment cost, PEC	B = 1.18 A	**$6,274,441**	
Direct installation costs			
Foundations & supports	0.12 B	$752,933	
Handling & erection	0.40 B	$2,509,776	
Electrical	0.01 B	$62,744	
Piping	0.30 B	$1,882,332	
Insulation for ductwork	0.01 B	$62,744	
Painting	0.01 B	$62,744	
Direct installation cost	0.85 B	**$5,333,275**	
Retrofit Factor:	1.3		
Direct Installation cost Including Retrofit Factor:		**$6,933,257.03**	
Site preparation	As required, estimate	$ 28,982.50	*$25,000*
Buildings	As required, estimate	$ 57,965.00	*$50,000*
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$13,294,645**	
INDIRECT COSTS (Installation)			
Engineering	0.10 B	$627,444	
Construction and field expenses	0.10 B	$627,444	
Contractor fees	0.10 B	$627,444	
Start-up	0.01 B	$62,744	
Performance test	0.01 B	$62,744	
Contingencies	0.03 B	$188,233	
Total Indirect Cost, IC	0.35 B	**$2,196,054**	
Total Indirect Cost of Required Baghouse (see baghouse calcs):			
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	2.20 B + SP + Bldg.	**$15,490,700**	

Cost for Hydrated Ash Reinjection Continued.

Cost Item				Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		0.5 hrs/shift	30.00 $/hr	$18,781	*$16,200*
Supervisor		15% of operator		$2,817	*$2,430*
Operating Materials	**Utilizes Recycled Lime in Ash**			-	
Maintenance					
Labor		0.5 hrs/shift	30.00 $/hr	$18,781	*$16,200*
Material		100% of maint. labor		$18,781	*$16,200*
Utilities					
Power Consumption:	**1.00% Bison Estimate**	(% of Electrical Generation)			
Electricity	3,766,800 (kWh/yr)				
Rate:	$0.06 $/kWh			$262,011	*$226,008*
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			$35,495	
Administrative Charges			2% of TCI	$309,814	
Property Taxes			1% of TCI	$154,907	
Insurance			1% of TCI	$154,907	
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)				$1,296,251	
			TOTAL ANNUAL COST (HAR)	**$2,272,545**	
			TOTAL ANNUAL COST FROM BAGHOUSE(S):	**$836,940**	
			)TAL ANNUAL COST FROM BAGHOUSE(S) AND HAR:	**$3,109,485**	
			Uncontrolled Emissions (tons/yr):	1231.00	
			Control Efficiency:	50.00%	
			Controlled Emissions (tons/yr):	615.5	
			Tons Removed (tons/yr):	615.5	
			Cost-Effectiveness ($/ton):	**$5,052**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

February 2011 = $ 100.00
August 2019 = $ 115.93
Ratio (2019/2011) = 1.1593

b) Capital cost scaled based on estimate from a vendor of $8M for a 75 MW plant.

Capital Recovery Factor

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

n = 20 years
i = 5.50% interest rate
CR = 0.0837

CELP

SO2 Cost Analysis

Costs for Spray Dry Absorber

Estimated using OAQPS example for Acid Gas Removal

Based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal

Cost Item	Factor	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT COSTS			
Purchased equipment costs			
Number of SDA systems required:		1	
Plant mW, per boiler (Gross)		43	
SDA Cost per kW:[b]		$ 150	
Cost per system + auxiliary equipment:		$ 7,477,485.00	*$6,450,000*
Total FDA + auxiliary equipment	A	$7,477,485	
Instrumentation	0.10 A	$747,749	
Sales taxes	0.03 A	$224,324.55	
Freight	0.05 A	$373,874	
Purchased equipment cost, PEC	B = 1.18 A	**$8,823,432**	
Direct installation costs			
Foundations & supports	0.12 B	$1,058,812	
Handling & erection	0.40 B	$3,529,373	
Electrical	0.01 B	$88,234	
Piping	0.30 B	$2,647,030	
Insulation for ductwork	0.01 B	$88,234	
Painting	0.01 B	$88,234	
Direct installation cost	0.85 B	**$7,499,917**	
Retrofit Factor:	1.3		
Direct Installation cost Including Retrofit Factor:		**$9,749,893**	
Site preparation	As required, estimate	$ 28,982.50	*$25,000*
Buildings	As required, estimate	$ 57,965.00	*$50,000*
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$18,660,272**	
INDIRECT COSTS (Installation)			
Engineering	0.10 B	$882,343	
Construction and field expenses	0.10 B	$882,343	
Contractor fees	0.10 B	$882,343	
Start-up	0.01 B	$88,234	
Performance test	0.01 B	$88,234	
Contingencies	0.03 B	$264,703	
Total Indirect Cost, IC	0.35 B	**$3,088,201**	
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	2.20 B + SP + Bldg.	**$21,748,474**	

Costs for Spray Dry Absorber
Continued.

Cost Item					Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT ANNUAL COSTS						
Operating Labor						
Operator	0.5	hrs/shift	30.00	$/hr	$18,781	*$16,200*
Supervisor	15%	of operator			$2,817	*$2,430*
Operating Materials					-	
SOx to be controlled (tons)			1231.00			
Ratio of sorbent to SOx[c]			1.4			
Lime required:	1508.71	tons/year				
lime cost ($/ton):	$100	estimate				
lime cost ($/year):					$174,905	*$150,871*
Maintenance						
Labor	0.5	hrs/shift	30.00	$/hr	$18,781	*$16,200*
Material	100%	of maint. labor			$18,781	*$16,200*
Utilities						
Power Consumption[d]:	1.75%	(% of Electrical Generation)				
Electricity	6,591,900	(kWh/yr)				
Rate:	$0.06	$/kWh			$458,519	*$395,514*
INDIRECT ANNUAL COSTS, IC						
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.			$35,495	
Administrative Charges			2%	of TCI	$434,969	
Property Taxes			1%	of TCI	$217,485	
Insurance			1%	of TCI	$217,485	
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)					$1,819,898	
				TOTAL ANNUAL COST (SDA):	**$3,417,916**	
				TOTAL ANNUAL COST FROM BAGHOUSE(S):	**$836,940**	
				TOTAL ANNUAL COST FROM BAGHOUSE(S) AND SDA:	**$4,254,856**	
				Uncontrolled Emissions (tons/yr):	1231.00	
				Control Efficiency:	80.00%	
				Controlled Emissions (tons/yr):	246.2	
				Tons Removed (tons/yr):	984.8	
				Cost-Effectiveness ($/ton):	**$4,321**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

February 2011 = $ 100.00
August 2019 = $ 115.93
Ratio (2019/2011) = 1.1593

b) Lowest Capital Cost in $/kW from EPA Air Pollution Control Fact Sheet for FGD, Dry Systems <200 MW: http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

c) Source: Air Pollution Engineering Manual, 2nd Edition, p265

d) Median of values, Source: http://www.nalcomobotec.com/technology/dry-sorbent-injection.html

Capital Recovery Factor

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

n = 20 years
i = 5.50% interest rate
CR = 0.0837

CELP

SO2 Cost Analysis

Costs for Dry Sorbent Injection

Estimated using OAQPS example for Acid Gas Removal

Based on methodology described in
EPA Pollution Cost Control Manual, 6th Edition
January 2002
Section 5.2, Chapter 1 Wet Scrubbers for Acid Gas Removal

Cost Item	Factor	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT COSTS			
Purchased equipment costs			
Number of hydrated ash systems required:		1	
Plant mW, per boiler (Gross)		43	
Cost per system + auxiliary equipment:[b]		$2,492,495	*$2,150,000*
Total FDA + auxiliary equipment	A	$2,492,495	
Instrumentation	0.10 A	$249,250	
Sales taxes	0.03 A	$74,774.85	
Freight	0.05 A	$124,625	
Purchased equipment cost, PEC	B = 1.18 A	**$2,941,144**	
Direct installation costs			
Foundations & supports	0.12 B	$352,937	
Handling & erection	0.40 B	$1,176,458	
Electrical	0.01 B	$29,411	
Piping	0.30 B	$882,343	
Insulation for ductwork	0.01 B	$29,411	
Painting	0.01 B	$29,411	
Direct installation cost	0.85 B	**$2,499,972**	
Retrofit Factor:	1.3		
Direct Installation cost Including Retrofit Factor:		**$3,249,964**	
Site preparation	As required, estimate	$28,983	*$25,000*
Buildings	As required, estimate	$57,965	*$50,000*
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$6,278,056**	
INDIRECT COSTS (Installation)			
Engineering	0.10 B	$294,114	
Construction and field expenses	0.10 B	$294,114	
Contractor fees	0.10 B	$294,114	
Start-up	0.01 B	$29,411	
Performance test	0.01 B	$29,411	
Contingencies	0.03 B	$88,234	
Total Indirect Cost, IC	0.35 B	**$1,029,400**	
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	2.20 B + SP + Bldg.	**$7,307,456**	

Costs for Dry Sorbent Injection Continued.

Cost Item					Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
DIRECT ANNUAL COSTS						
Operating Labor						
Operator	0.5	hrs/shift	30.00	$/hr	$18,781	*$16,200*
Supervisor	15%	of operator			$2,817	*$2,430*
Operating Materials					-	
SOx to be controlled (tons)			1231.00			
Ratio of sorbent to SOx[c]:			3			
Lime required:			3232.96	tons/year		
lime cost ($/ton):			$100	estimate		
lime cost ($/year):					$374,797	*$323,296*
Maintenance						
Labor	0.5	hrs/shift	30.00	$/hr	$18,781	*$16,200*
Material	100%	of maint. labor			$18,781	*$16,200*
Utilities						
Power Consumption[d]:	0.30%	(% of Electrical Generation)				
Electricity	1,130,040	(kWh/yr)				
Rate:	$0.06	$/kWh			$78,603	*$67,802*
INDIRECT ANNUAL COSTS, IC						
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.			$35,495	
Administrative Charges			2%	of TCI	$146,149	
Property Taxes			1%	of TCI	$73,075	
Insurance			1%	of TCI	$73,075	
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)					$611,483	
				TOTAL ANNUAL COST (DSI):	**$1,451,836**	
				TOTAL ANNUAL COST FROM BAGHOUSE(S):	**$836,940**	
				TOTAL ANNUAL COST FROM DSI AND BAGHOUSE(S):	**$2,288,776**	
				Uncontrolled Emissions (tons/yr):	1231.00	
				Control Efficiency:	50.00%	
				Controlled Emissions (tons/yr):	615.5	
				Tons Removed (tons/yr):	615.5	
				Cost-Effectiveness ($/ton):	**$3,719**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019. https://www.bls.gov/data/inflation_calculator.htm

February 2011 = $ 100.00
August 2019 = $ 115.93
Ratio (2019/2011) = 1.1593

b) Dry Sorbent Injection Systems can cost ~$40 - $50/kW: http://www.nalcomobotec.com/technology/dry-sorbent-injection.html

c) Source: Air Pollution Engineering Manual, 2nd Edition, p264

d) Median of values, Source: http://www.nalcomobotec.com/technology/dry-sorbent-injection.html

Capital Recovery Factor

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

n = 20 years
i = 5.50% interest rate
CR = 0.0837

CELP
Replacement of Baghouses for SOx Controls

Reference: OAQPS Control Cost Manual Fifth Edition, Chapter 5 (December 1998)

By these calculations from Chapter 5 of Manual

Stack Flowrate [a]	234,257	ACFM
Stack Flowrate [a]	124,467	dscfm
Operating Hours	8,760	hrs/yr
Pressure Drop:		
Baghouse (mean from Section 5.2.2):	7.5	in. of H_20

Baghouse Electricity Costs:	0.00181(Q)(delta P)(hours per year)	
Power (kWh/yr)=	2,785,714	kWh/yr
Cost per kWh=	$0.060	Bison Estimate
Cost of Electricity=	$167,143	

Compressed Air Costs:	
flow needed (2 scfm/1,000 acfm)	2
cost (per 1,000 scfm)[b]	0.36
cost per min	$0.17
cost per hour	$10.04
cost per year	$87,942.25

Cost of Bags (based on vendor estimate for similar project)	**Cost: 2019 Inflation Adjustment[c]**	***Cost: 2011 Analysis***
Fiberglass Bags	$231,860	*$200,000*

Notes:

a) 2008 Stack Test Data

b) Scaled per the Chemical Engineering Plant Cost Index (1998 & 2010)

Annual avg	CEPCI98 =	389.5
Annual avg (proposed)	CEPCI10 =	556.4

c) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019.
https://www.bls.gov/data/inflation_calculator.htm

February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

CELP
Replacement of Baghouse for SOx Controls
Total Capital Costs for Fabric Filter Baghouse with Fiberglass Bags

Reference: OAQPS Control Cost Manual Fifth Edition, Chapter 5 (December 1998) and associated CO$T-AIR spreadsheet

Cost Component	Equation	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Direct Costs			
Purchased Equipment Costs			
Baghouses Needed		1	
Capital Cost per scfm:[b]		$ 16	
SCFM:		124,467	
Cost per Baghouse (estimate):		$ 2,308,707.31	*$ 1,991,467*
Total Equipment Costs	Sum=A	$2,308,707	
Instrumentation	0.1A	$230,871	
Equipment Tax:	0.03A	$69,261	
Freight	0.05A	$115,435	
Purchased Equipment Cost	Sum=B	$2,724,275	
Direct Installation Costs			
Foundation and Supports	0.04B	$108,971	
Handling and Erection	0.5B	$1,362,137	
Electrical	0.08B	$217,942	
Piping	0.01B	$27,243	
Insulation for Ductwork	0.07B	$190,699	
Painting	0.04B	$108,971	
Direct Installation Costs	0.74B	$2,015,963	
Retrofit Factor:	1.3		
Direct Installation Costs Including Retrofit Factor		$2,620,752	
Site Preparation		$ 115,930	*$ 100,000*
Facilities and Buildings		Not Calculated	
Total Direct Costs	1.74B + Retrofit	**$5,460,957**	
Indirect Costs			
Engineering	0.1B	$272,427	
Construction and Field Expenses	0.2B	$544,855	
Contractor Fees	0.1B	$272,427	
Start-up	0.01B	$27,243	
Performance Test	0.01B	$27,243	
Contingencies	0.03B	$81,728	
Total Indirect Costs	0.45B	**$1,225,924**	
Total Capital Investment	2.19B	**$6,686,880**	

Total Capital Costs for Fabric Filter Baghouse with Fiberglass Bags Continued.
Total Annual Costs

Reference: OAQPS Control Cost Manual Fifth Edition, Chapter 5 (December 1998)

Cost Component		Equation	Cost: 2019 Inflation Adjustment[a]	*Cost: 2011 Analysis*
Direct Annual Costs				
Operating Labor				
	Operator	2 hr/shift x 3 shifts/day x 365 days/yr x $30.00/hr	$76,166	*$65,700*
	Supervisor	15% of operator	$11,425	*$9,855*
Operating Materials				
Maintenance				
	Labor	1 hr/shift x 3 shifts/day x 365 days/yr x $30.00/hr	$38,083	*$32,850*
	Materials	100% of Maintenance Labor	$38,083	*$32,850*
	Replacement Bags	(Future worth at 3 years and 10%=0.4021*cost of bags)	$108,083	*$93,231*
Utilities				
	Electricity	0.000181(Q, acfm)(dP, in. H2O)(hr/yr)*$40.00/MWh/yr)	$111,429	
	Compressed Air	2 scfm/1,000acfm(Q)($0.25/1,000scfm)(60min/hr)(hrs/yr)	$87,942	
	Total DC		**$471,210**	
Indirect Annual Costs				
Overhead		60% of sum of Operating Labor and Operating Materials	$98,254	
Administrative Charges		2% of Total Capital Investment	$133,738	
Property Tax		1% of Total Capital Investment	$66,869	
Insurance		1% of Total Capital Investment	$66,869	
Capital Recovery (from TCI spreadsheet)		at 5.5% for 20 years (CRF x Total Capital Investment)	$0	
	Total IC		**$365,729**	
Total Annual Cost ($)		Sum of Total DC and Total IC	**$836,940**	

Notes:

a) Inflation adjustments are based upon the CPI Inflation Calculator provided by the Bureau of Labor Statistics. According to the calculator, $100 in February 2011 is equivalent to $115.93 in August 2019.

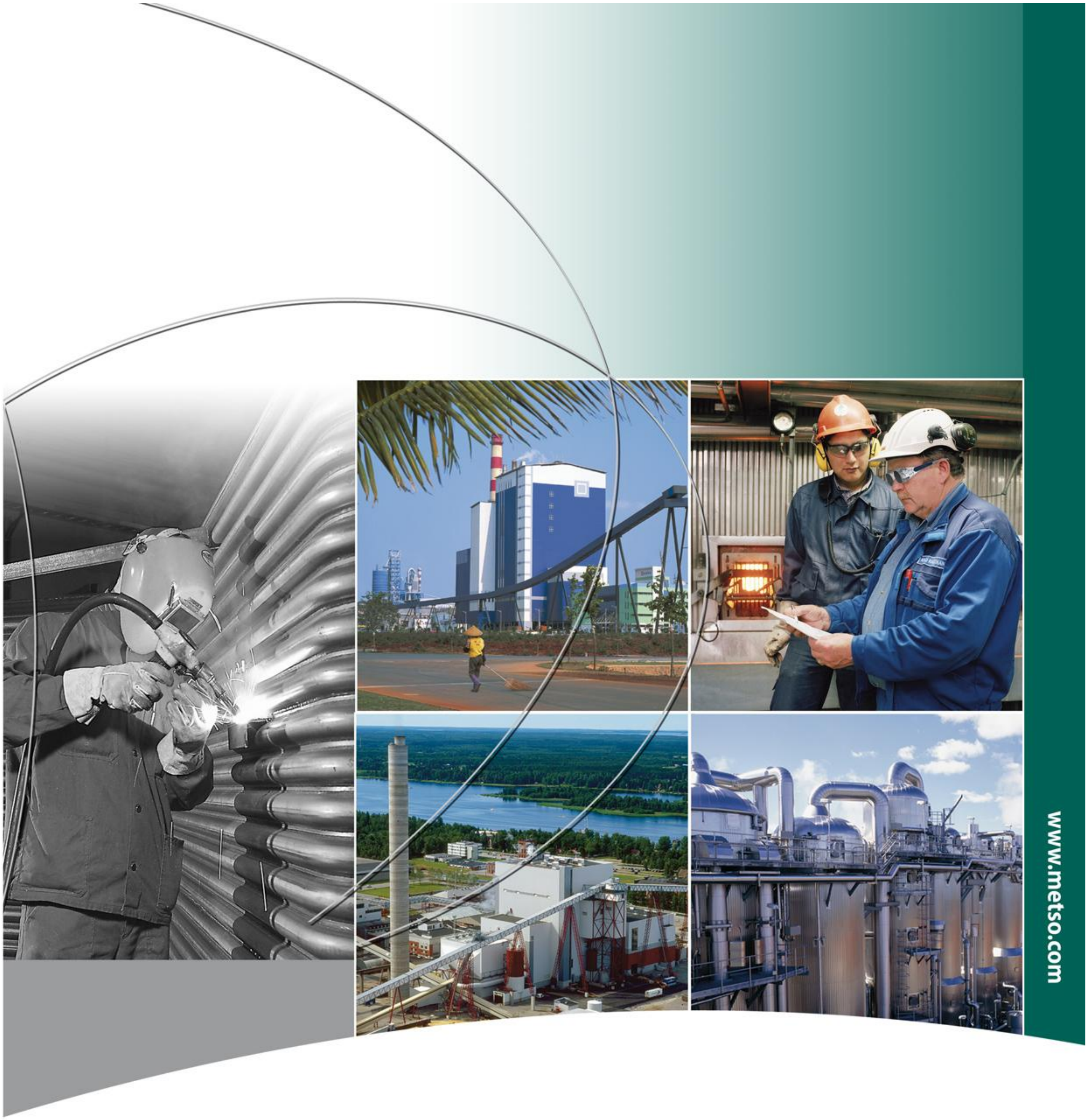
February 2011 =	$	100.00
August 2019 =	$	115.93
Ratio (2019/2011) =		1.1593

b) Median Value from Air Pollution Control Technology Factsheet, Fabric Filters.http://www.epa.gov/ttn/catc/dir1/ff-pulse.pdf

Capital Recovery Factor

n =	20	years
i =	5.50%	interest rate
CR =	0.0837	

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$



ECONOMIC EVALUATION OF NOX CONTROL

Colstrip Energy Limited Partnership

Colstrip Montana

METSO REFERENCE No. 710070

Feb 2011

metso
Expect results

Executive Summary

Metso was contracted to provide an economic evaluation of NOx control for the Circulating Fluidized Bed Boiler (CFB) at the Colstrip Energy Limited Partnership (CELP) facility in Colstrip MT. This estimate was compiled using information available from drawings of the plant that are in Metso's archives. The drawings do not show balance of plant piping, cable trays, and modifications that have been made to the facility. There could be interferences and significant unknowns that would alter Metso's conclusions contained within this report. This is an order of magnitude estimate.

Metso evaluated the use of SCR and SNCR technology to reduce NOx emissions at the facility. The SNCR is capable of reducing NOx emissions by at least 50% while the SCR is capable of practical reductions of 80%. The installed cost of the SCR is estimated to be between 13 and 17 times the cost of the installed estimate for an SNCR system. The installed cost of an SCR ranges from between $10,500,000 and $13,500,000 whereas the SNCR system will cost approximately $800,000 installed. The operation and maintenance (O&M) costs for the SCR are approximately 1.7 times the costs for the SNCR system. The increased cost for 30% additional reduction in NOx emissions by the installation of an SCR system at this facility is significant.

Many of the Metso supplied CFBs utilize SNCRs to reduce NOx emissions. There are not any SCRs installed on Metso supplied CFBs in the United States. The costs and performance of SNCRs systems are much more predictable than SCR solutions. The SNCR solution can be implemented more expediently than the SCR solution. The SNCR system can be installed during a short outage while the SCR solution tie-in will require a 2-3 month outage.

There are many variables that could negatively affect the performance of the SCR. The SCR could foul from the high dust environment. The SCR could contribute to fouling of downstream equipment. The SCR performance could be less than expected because of the lack of an ideal layout that could be obtained on a new boiler application. The application would need to be modeled first by CFD (computational fluid dynamics) and then with a scaled physical model before any performance guarantees could be supplied. There will still be some uncertainty in the actual performance of the SCR.

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Overview –

There is one Circulating Fluidized Bed Boiler at the CELP facility. The boiler is rated for 355,000 lb/hr at 1300 psig and 955F main steam. Current fuel is waste coal as per below:

Coal Rank	Higher Heating Value	Typical Coal Moisture Content	Average Ash Content	Average Sulfur Content
Waste Coal	8,300 Btu/lb	20-25%	13.8%	1.5%

The purpose of this assessment is to provide estimated capital and O&M costs for NOx control solutions.

- The average uncontrolled NOx for Colstrip (CELP) is .40 lb/MMBTU.

The following solutions were evaluated

- An SNCR system capable of 50% NOx reduction for controlled NOx rates of .2 lb/MMBTU
- An SCR system capable of ~80% reduction for controlled NOx rates of .08 lb/MMBTU. An 80% reduction rate is a practical rate for an SCR in this application.

Both solutions require a method for the storage and supply of ammonia to the process. An aqueous ammonia system was selected for the evaluation.

Aqueous ammonia system

SYSTEM DESCRIPTION:

The ammonia system is similar for both the SNCR and the SCR. The ammonia system consists of a storage tank and forwarding skid.

The aqueous ammonia system tank and metering system consists of a 14,000 gal ammonia tank with metering pumps, filters, tank level sensor and alarm, caged ladder for access to top of tank, and other attachments. The tank can contain approximately 9.5 days of storage of 19.5% aqueous ammonia using the SNCR system while providing 50% NOx reduction. The larger tank will allow more flexibility in filling cycle. The tank is sized to contain slightly more than 2 standard tank truck loads of aqueous ammonia.

Location and Installation Considerations

The tank and forwarding skid would be located on the ground, outside of the boiler house. A containment dike is installed around the tank to capture the fluid if a leak or rupture occurs.

Selective noncatalytic reduction system (SNCR)

System Description:

An SNCR system for a CFB consists of the aqueous ammonia system listed above, small bore piping from the metering skid to the boiler, and injection nozzles at the boiler.

Steam or compressed air is used to atomize and distribute the ammonia into the cyclone inlet ducts. If the system is to be used intermittently, purge air would be installed to keep the nozzles clear of material when the system is not in use.

A single line will be routed from the forwarding system to boiler. The line will split up near the boiler to feed two metering skids, one at each cyclone inlet. The metering skids will be used to bias ammonia flow to each nozzle.

Location and Installation Considerations

The distribution panels and injection nozzles are located near the cyclone inlet ducts. The injection nozzles penetrate and are attached to the cyclone inlet ducts. Four injection nozzles will be installed on each cyclone inlet duct to maximize the distribution of ammonia into the flue gas stream. This location provides an area of high velocity and narrow duct width to allow for good penetration and mixing of the ammonia with the flue gas. Higher reduction rates are achievable on CFBs than for BFBs, and other boiler types because of this optimum spray location. Ammonia slip increases with the reduction rate however. Standard guaranteed reduction rates are in the 50% range while maintaining slip to 10 ppm or below.

Time for Compliance

An SNCR system could be installed within 16-24 weeks. A maximum 2 week outage would be required to make tie-ins.

Capital Costs and Downtime

The installed estimate for the SNCR system is $800,000. Control technologies are often evaluated based on $/kw basis. The gross electrical generation for the Colstrip unit is 43 MW. The estimated installed cost for the SNCR is $19/kw(gross electrical).

The tie- in can be made during the normal annual outage.

OPERATING AND MAINTENANCE CONSIDERATIONS

The O&M costs are expected to be approximately $500,000. Most of this is the cost of the ammonia. Ammonia consumption is $478,000 based on $196/delivered ton. Maintenance of the ammonia system and nozzles should average $10,000-15,000.

OTHER NON-ENVIRONMENTAL IMPACTS

SNCRs are the primary method of NOx control on the majority of CFBs and no problems have been noted. Metso has not observed nor is aware of any increased fouling, decreased pressure part life, or other issues associated with the use of SNCRs that are operating at 50% reduction levels.

Selective catalytic reduction system (SCR)

SYSTEM DESCRIPTION:

An SCR is an array of catalyst installed in an existing duct or in a dedicated enclosure. Ammonia is injected upstream of the catalyst. The catalyst enhances the reaction rate between the ammonia and the NOx, thus high capture efficiencies can be attained.

The temperature range for proper operation of an SCR is between 480F to 800F. The optimum operation of an SCR depends on straight, uniform, and optimum flue gas velocities across the catalyst grid. When optimum conditions exist, SCRs are capable of up to 90% reduction of NOx in clean flue gas streams. For practical retrofits, especially on smaller units, optimum conditions do not exist without significant capital modifications.

Clean flue gas streams are often not practical, especially on an existing boiler. The reason is that the cleaner portion of a flue gas stream is located after a baghouse or a precipitator. The temperature of the flue gas stream is too low in these areas for proper operation of an SCR. Many of the CFBs in the United States have baghouses for particulate control. The normal maximum allowable temperature for a baghouse is 400F. This is still too low for the operation of an SCR. Therefore, on some installations, a regenerative SCR is installed. Regenerative SCRs are expensive to install and expensive to operate because an RSCR requires the use of burners to heat up the flue gas stream in order for the NOx capture to occur. This is often an efficiency decrease for the boiler, significant increase in operating cost, and often not a practical solution. For this reason, Metso did not evaluate the use of an RSCR.

Metso evaluated the use of a high dust SCR for this installation based on the above information.

A vaporizer in the ammonia delivery system is required for an SCR to inject the ammonia in gaseous form.

LOCATION AND INSTALLATION CONSIDERATIONS

The effective temperature range for an SCR is 480F to 800F. As can be seen from the general arrangements drawings there are three locations that could be utilized within the current plant arrangement.

1. Upstream of economizer
2. Between economizer and airheater.
3. Downstream of airheater.

Upstream of the economizer –

The flue gas temperature upstream of the economizer is 880F. The gas in this location is turbulent, after exiting the primary superheater bundle. Additionally the flue gas is changing direction in this area. The proper operation of an SCR is dependent on uniform flue gas flow across the catalyst grid, thus Metso would not recommend installing an SCR in this location.

Between economizer and airheater –

The flue gas temperature between the economizer and airheater is 450F. This is a suitable temperature, slightly on the low side for optimum performance on an SCR. There is not enough room between the exit of the economizer and inlet to the airheater to install an in-duct SCR. There is not enough space to pull flue gas from this location and route into an SCR and then back to the airheater via additional ductwork.

Downstream of airheater

The flue gas temperature is 300-330F at the exit of the tubular airheater. This temperature is too low for proper operation of an SCR.

Proposed Solution

A new bay could be added to the building in the location between the airheater and the baghouse. The airheater could be moved to this new bay and an SCR could be installed above the airheater. A new hopper and flue gas duct would connect the discharge of the economizer to the inlet of the SCR located in the new bay. The existing hopper and new ductwork would be located downstream of the airheater to connect the discharge of the airheater to the inlet to the baghouse.

TIME FOR COMPLIANCE

The normal lead time for an SCR is 16-24 months, with an additional 2 months to make the necessary recommended modifications.

CAPITAL COSTS AND DOWNTIME

The engineering and supply estimate for the SCR, ductwork, steel, and other equipment is $5,500,000.

Installation of the SCR will be a challenge as proposed. A new bay will be added outside the boiler building, however significant modifications would be required within the boiler building. Metso believes the airheater should be relocated to the new bay and the SCR will be installed above the airheater. This is a very challenging and expensive retrofit solution with many unknowns. The area where modifications are required is congested. This will make installation challenging due to lack of space. There is uncertainty in the installation estimate due to significant mechanical modifications required at the site. The Harris Group Inc., has estimated the installation costs to be between $5,000,000 to $8,000,000 for the SCR solution.

The estimated installed cost for SCR technology is between $10,500,000 to 13,500,000.

This equates to being between $233/kw and $314/kw (gross electrical), assuming 43MW gross electrical generation.

Significant mechanical retrofits will be required. A 2-3 month outage would be required to make the necessary modifications and tie-ins. The cost of lost generation has not been estimated since Metso does not know the load profile and power sales rate structure.

OPERATING AND MAINTENANCE CONSIDERATIONS

The O&M costs are expected to be approximately $830,000 for the SCR when catalyst costs and installation are factored in.

An SCR introduces additional pressure drop in the system. A 4” pressure drop translates into $85,000 per year at $.06/kw.

The ammonia usage is less for an SCR than an SNCR. The predicted ammonia consumption will add $288,000 to the operating costs of the plant.

Catalyst maintenance costs for the SCR are expected to annually average $440,000 including catalyst costs, removal and installation, and catalyst disposal costs. The costs could be on the lower end because of unknowns regarding catalyst life resulting from the fly ash and constituents in the flue gas. It is recommended that a detailed review of catalyst fouling potential be performed prior to selecting SCR technology as a method of NOx control on this unit.

OTHER NON-ENVIRONMENTAL IMPACTS

SCRs can contribute to airheater fouling from the formation of ammonium sulfate. Airheater fouling could reduce unit efficiency, increase flue gas velocities in the airheater, cause corrosion, and erosion.

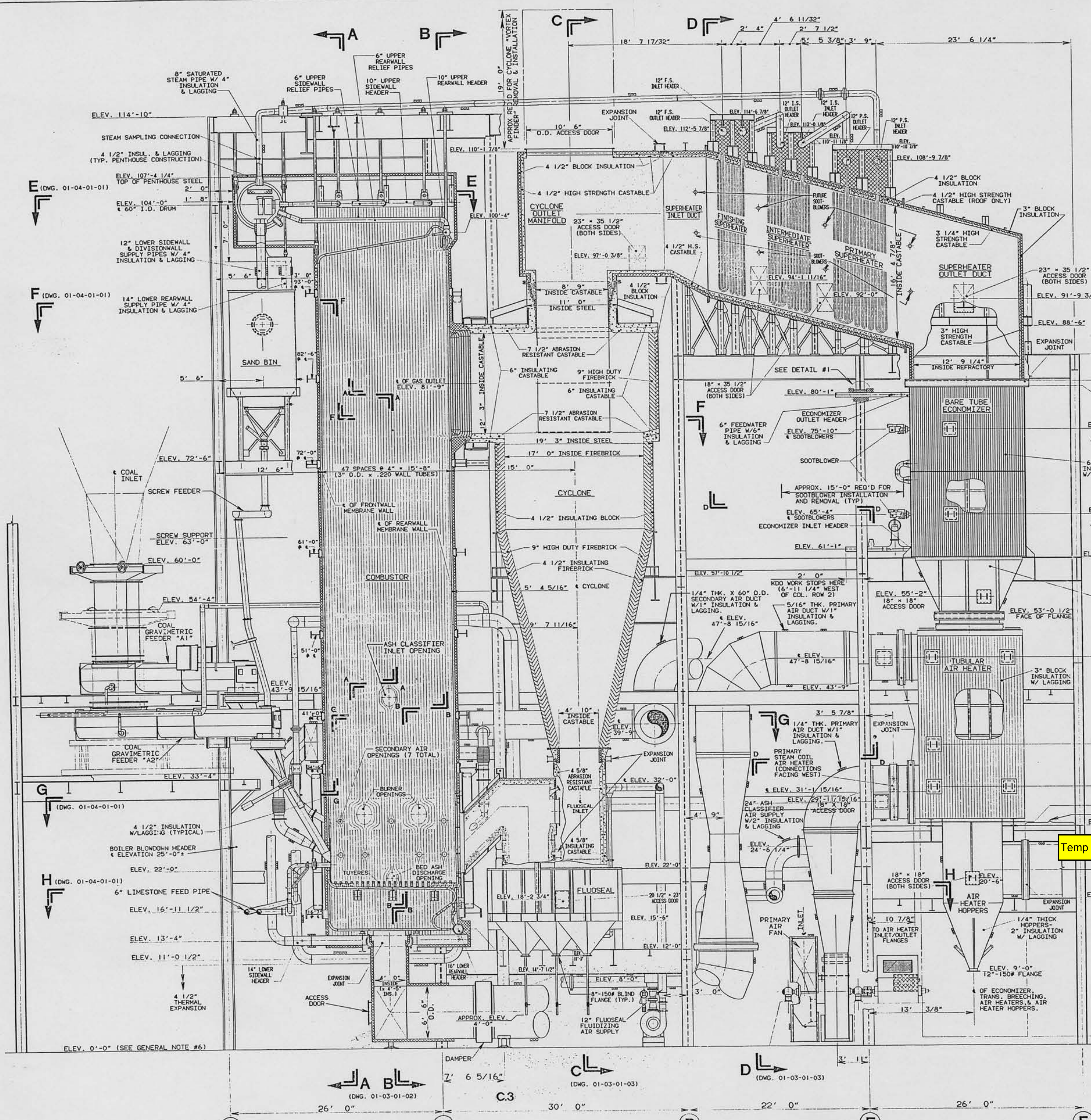
Catalyst replacement can lengthen boiler outages, especially in retrofit installations, where space and access is limited. This is a retrofit installation in a high dust environment thus fouling is likely, which could lead to unplanned outages or less time between planned outages.

On some installations, catalyst life is short and SCRs have fouled in high dust environments. This had led to downtime on other units within the fleet in overseas installations. A detailed assessment of catalyst life cost would require further analysis by a catalyst vendor.

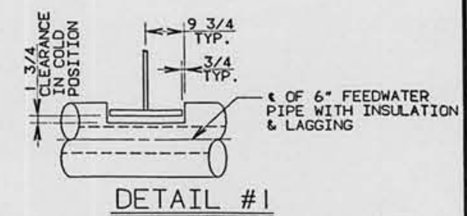
TABLE 1: Summary Table of Assessment of NOx Control Economic Evaluation

				Colstrip (CELP)		
				SNCR(50%)	SCR(80%) cost range	
Cost of compliance		Eng and Supply		$ 625,000	$ 5,500,000	$ 5,500,000
		Installation		$ 175,000	$ 5,000,000	$ 8,000,000
		Total installed costs		**$ 800,000**	**$ 10,500,000**	**$ 13,500,000**
	Other Capital Costs	ID fan upgrade			may need to upgrade ID fan (in range of estimate above)	
	O&M(avg yearly) for each unit - **subtotal of costs below**		$/yr	**$ 493,397**	**$ 827,789**	
		Ammonia sys maint	$/yr	$ 15,000	$ 10,000	
		sootblower	$/yr		$ 5,000	
		SCR catalyst	$/yr		$ 248,850	
		Catalyst install	$/yr		$ 151,200	
		SCR disposal	$/yr		$ 40,000	
		additional pressure drop	$/yr		$ 85,701	
		Ammonia cost (each unit)	$/yr	$ 478,397	$ 287,038	
Time necessary for compliance		supply and install		24-30 wks	26 months	
Energy and non-air quality environmental impacts of compliance		unit downtime, loss of revenue		2 week outage	2 months no production	
		ash resale problems		none reported	unknown	
		fouling		unlikely	likely	
Remaining useful life of affected source				19	19	

SCR Installation order of magnitdue estimate by Harris Group Inc.



SECTIONAL RIGHT SIDE ELEVATION
(LOOKING WEST)



DETAIL #1
SCALE : 1/2"=1'-0"

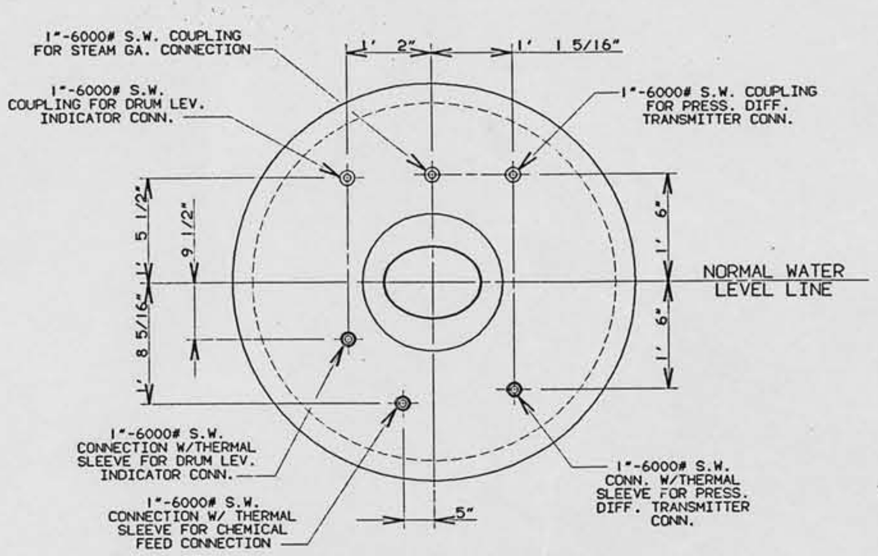
NOTE TO INSULATION CONTRACTOR: INSULATE & LAG AS SHOWN IN THIS AREA TO ALLOW FOR THERMAL EXPANSION.

DESIGN DATA

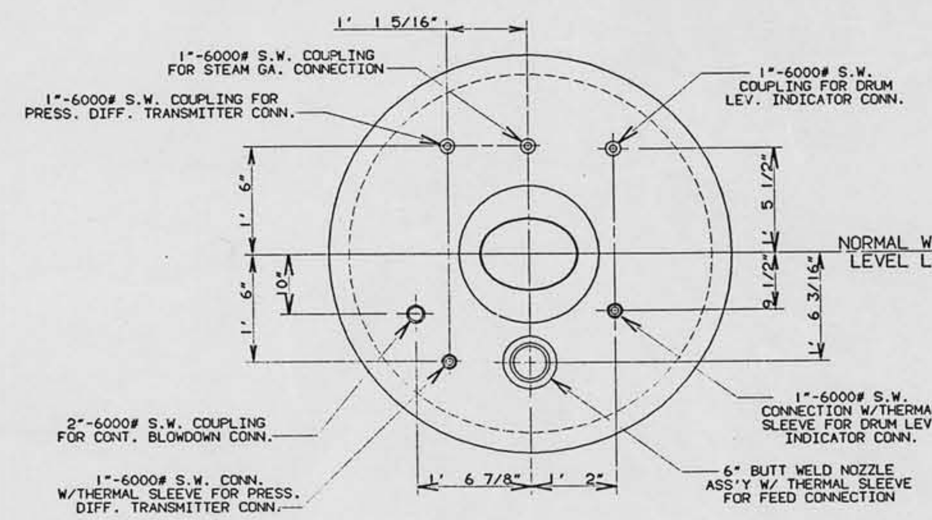
1. STEAM CAPACITY-CONTINUOUS..........................355,000#/HR.
2. DESIGN PRESSURE..........................1575 PSIG.
3. OPERATING PRESSURE AT STEAM OUTLET(S.H. HEADER).....1300 PSIG.
4. STEAM TEMPERATURE(AT NON-RETURN VALVE OUTLET).......955°F.(±10°F.)
5. FEEDWATER TEMPERATURE AT ECONOMIZER INLET...........358°F.
6. COMBUSTOR VOLUME(INCLUDING DENSE BED)..............31,800 FT^3
7. TYPE OF FIRING......................CIRCULATING FLUIDIZED BED
   START-UP BURNER......................NO. 2 OIL
8. ECONOMIZER DESIGN PRESSURE(TUBE SIDE)..............1700 PSIG.

HEATING SURFACE

1. COMBUSTOR-FLAT PROJECTED..........................9,925 FT^2
2. SUPERHEATER (TOTAL)..........................20,365 FT^2
   A. PRIMARY............8,920 FT^2
   B. INTERMEDIATE........7,011 FT^2
   C. FINISHING..........4,434 FT^2
3. ECONOMIZER..........................27,216 FT^2
4. AIRHEATER..........................PRIMARY - 13,616 FT^2
   SECONDARY - 7,444 FT^2



RIGHT SIDE DRUM HEAD CONNECTIONS
NO SCALE



LEFT SIDE DRUM HEAD CONNECTIONS
NO SCALE

TO AUXILIARY EQUIPMENT- SEE AUX. EQUIP. DWG. 01-20-01-01(SIDE ELEVATION) & 01-02-01-02(PLAN VIEW)

GENERAL NOTES

1. FOR ADDITIONAL GENERAL ARRANGEMENT VIEWS & SECTIONS, REFER TO DRAWINGS NO. 01-02-01-01, 01-03-01-02, 01-03-01-03, 01-04-01-01, 01-20-01-01, & 01-02-01-02.
2. FOR PRESSURE PART ARRANGEMENT DETAILS, REFER TO DRAWINGS 01-05-01-01 THRU 01-05-01-06.
3. "N/F" DENOTES NOT FURNISHED BY KEELER DORR-OLIVER.
4. STRUCTURAL STEEL, FOUNDATION & FOUNDATION WORK N/F.
5. FOR PLOT PLAN, REFER TO DRAWING NO. 01-08-01-01.
6. DATUM ELEVATION 0'-0" IS EQUIVALENT TO 3104'-0" ABOVE SEA LEVEL.
7. INSULATION, LAGGING, & REFRACTORY NOT FURNISHED.
8. INSULATION & LAGGING THICKNESS ARE SHOWN FOR REFERENCE ONLY.
9. STRUCTURAL STEEL SHOWN ON THIS DRAWING IS FOR CONCEPTUAL USE ONLY. CUSTOMER'S STEEL ARRG'TS. MUST BE UTILIZED FOR ERECTION PURPOSES.

REV.	REVISIONS	DATE	BY	CK'D
05	ADDED DAMPER TO PRIMARY AIR DUCT, ADDED PURGE AIR PIPING, ADDED COMBUSTOR VOLUME, REVISED FEEDWATER INLET VALVES	9/19/89	SED MAF	MAF
04	ADDED LOWER COAL FEED VALVE, REV'D DOORWAY ON SANDBIN, & ADDED NORMAL WATER LEVEL LINE ON DRUM HEADS	6/30/89	SED	---
03	REV'D ASH CLASS AIR SUPPLY PIPING & COAL FEED SYSTEM, AND ADDED FUTURE SOOTBLOWERS & DETAIL #1	5/13/89	SED	---
02	REV'D COAL FEED SYSTEM, LIMESTONE FEED PIPING, & NOTES REMOVED FUTURE SOOT-BLOWERS AND SCREW SUPPORT ELEV WAS 64'-8"	5/1/89	SED	---
01	REV'D FLUOSEAL FLUIDIZING AIR SUPPLY PIPING, REV'D CASTABLE IN SUPERHEATER & IN CYCLONE	3/13/89	SED	---

REV.	REVISIONS	DATE	BY	CK'D
01	REV'D GRAVIMETRIC FEEDERS, ADDED FEEDER SUPPORT STEEL, ADDED S.H. DRAIN HEADERS, REV'D FLUOSEAL DISCHARGE LEG	3/13/89	SED	---
01	MOVED ACCESS DOOR ON PRIMARY AIR DUCT & ON AIR HEATER HOPPER ADDED NOTE FOR REMOVABLE GRATING, REMOVED ACCESS DOOR FROM FLUOSEAL	2/28/89	SED	---
01	REVISED SAND BIN, ADDED SCREW FEEDER & PIPING, ADDED NORTH ARROW, AIR HEATER HOPPER OUTLET DUCT WAS AT ELEV 21'-0"	2/28/89	SED	---
01	ADDED ASH CLASS AIR SUPPLY PIPING, REVISED VORTEX FINDER, ADDED PLATFORM ELEV AT 18'-0" & 43'-9" BETWEEN COL E & F	2/28/89	SED	---
01	ADDED ELEV TO NOTE #6, ADDED VALVES TO FLUOSEAL HOPPERS, ADDED DIMENSION TO ℄ OF VENTURI, ADDED INSULATION & [illegible]	2/28/89	SED	---

PROJECT	MONTANA ONE PROJECT COLSTRIP, MT. 1-355,000 #/HR. TYPE "HCFS" BOILER
DRAWN BY	M.A.F.
DATE	7-15-88
SCALE	3/16"= 1'-0"
CHECKED BY	---
MADE FROM	429-038
APPROVED BY	
CONTRACT NO.	17337
DRAWING NO.	01-03-01-01
REV.	05

GENERAL ARRANGEMENT- SECTIONAL SIDE ELEVATION

CADAM DRAWING
DO NOT REVISE MANUALLY