Air, Energy & Mining Division

Montana's Regional Haze State Implementation Plan for the Second Planning Period
Compilation of Federal Land Manager and Public Comments and Montana's Responses Thereto

The following appendices contain comments received during the formal FLM comment period, September 27, 2021 - November 22, 2021 (Appendix F) and during the official public comment period, February 3, 2022 – March 4, 2022 (Appendix H).

Appendix G contains documentation of Montana's public comment period and hearing.

Appendix I contains Montana's response to comments received during the formal FLM comment period and the official public comment period.

APPENDIX F – FEDERAL LAND MANAGER COMMENTS

1 - USFS COMMENTS

United States Department of Agriculture | Forest Service | Region One

Northern Region
26 Fort Missoula Road
Missoula, MT 59804

File Code: 2580
Date: November 22, 2021

Chris Dorrington
Director, Montana Department of Environmental Quality
1520 E. 6th Avenue
Helena, MT 59601

Dear Mr. Dorrington:

On September 27th, 2021, the State of Montana submitted a draft Regional Haze State Implementation Plan describing your proposal to continue improving air quality by reducing regional haze impacts at mandatory Class I areas across the Region. We appreciate the opportunity to work closely with your State through the initial evaluation, development, and subsequent review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I areas.

This letter acknowledges that the U.S. Department of Agriculture, U.S. Forest Service, has received and conducted a substantive review of your proposed Regional Haze State Implementation Plan. This review satisfies your requirements under the federal regulations 40 C.F.R. § 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the authority to approve the document.

We have attached comments to this letter based on our review. We look forward to your response required by 40 C.F.R. § 51.308(i)(3). For further information, please contact Jill Webster at jill.webster@usda or (406) 361-5380.

Again, we appreciate the opportunity to work closely with the State of Montana. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

Digitally signed by LEANNE MARTEN
Date: 2021.11.22 14:49:18 -07'00'

LEANNE M. MARTEN
Regional Forester

Enclosure

cc: Sonja Nowakowski, Rhonda Payne, Brandon McGuire, Bill Avey, Kurt Steele, Cheri Ford, Chad Benson, Matt Anderson, John Hagengruber

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<u>Montana DRAFT Regional Haze State Implementation Plan (SIP)</u>

<u>Technical Comments</u>

The USFS recognizes and applauds the emission reductions made in Montana since the early 2000's. Further, we appreciate the strong working relationship among our respective staff and the routine communications during the development of this draft Regional Haze plan.

Overall, the USFS finds that the draft SIP is well organized and comprehensive. The USFS requests that the Montana Department of Environmental Quality consider the following before final adoption of the SIP.

Inappropriate Use of Glideslope as a Safe Harbor

The SIP concludes that no additional measures are needed based on emission reductions from recent source retirements and projected visibility at Class I areas being below their uniform rates of progress (URPs). The USFS believes that the Regional Haze Rule implies continual progress and that each planning cycle must include a thorough assessment of potential cost-effective reductions. The USFS believes this "safe harbor" argument is erroneous and is not supported by the Regional Haze Rule. The EPA reiterated this in its clarification memo dated July 8th, 2021:

> *The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is "reasonable progress."*

Cost Effective Controls Identified, But Not Considered

Montana relies heavily on the emissions reductions due to shutdowns of several electric generating units (EGUs) over the past planning period. While these shutdowns do result in decreases in visibility impairing pollutants, it does not preclude the State from considering cost-effective controls during this planning period.

Montana does not define a cost-effective value, in dollars per ton of emission reductions. However, it does identify controls for several sources, at a cost per ton, that has been deemed cost effective by other states and EPA. In addition, projected costs for controls will likely be even lower if estimated using current interest rates. We ask that the State reconsider emissions reducing controls, particularly those at the lower end of the cost range., e.g. nitrogen oxide controls identified for Colstrip Energy Limited Partnership (Rosebud Power Plant), Yellowstone Energy Limited Partnership, and Sidney Sugars.

Prescribed Fire Emissions

Fire plays an important role in shaping the vegetation and landscape in Montana and surrounding states. Recurring fire has been a part of the landscape for thousands of years. Aggressive fire suppression, coupled with an array of other disturbances has changed the historic composition and structure of the forests. Periodic prescribed burning and other vegetation management can recreate the ecological role of fire in a controlled manner. Fire and fuels management supports a variety of desired conditions and objectives across the forests and grasslands (e.g., community protection, hazardous fuels reduction, native ecosystems restoration, historic fire regimes restoration, wildlife openings, and open woodland creation, etc.). The USFS along with our partners, including the Montana Department of Natural Resources and Conservation (DNRC), plan to increase the use of prescribed fire to accomplish these goals.

The 2017 Regional Haze Rule includes a provision to allow states to adjust the glidepath to account for prescribed fire. The draft SIP states that prescribed fire emissions were taken from the 2014v2 National Emissions Inventory (NEI) and were carried forward into the 2028 future year emissions. Recent data on prescribed fire activity, especially within the USFS, shows that the number of acres burned have increased since the development of the 2014v2 emissions inventory and are projected to increase through the planning period. Therefore, keeping prescribed fire emissions steady to 2028 undercounts these emissions. Nevertheless, the USFS is requesting that Montana adjust the glidepaths for its prescribed fire projections to reflect these adjusted estimates, as a clear acknowledgement of the shared state and federal goals of restoring fire adapted ecosystems. The Future Fire Scenario (FFS2) modeling provided by the Western Regional Air Partnership provides an updated and more accurate assessment of prescribed burning in Montana and surrounding states.

2 - NPS COMMENTS

National Park Service (NPS) Regional Haze SIP feedback for the Montana, Department of Environmental Quality

December 2, 2021

Contents

Executive Summary

The National Park Service (NPS) Air Resources Division (ARD) appreciates the opportunity to review the September 27, 2021 federal land manager (FLM) draft of the State of Montana Regional Haze Implementation Plan for the Second Planning Period (2018–2028). The Montana Department of Environmental Quality (MDEQ), Air Quality Bureau offered to hold a consultation meeting with the NPS and, on request, granted a one-week extension to the 60-day consultation period. NPS ARD staff elected not to hold a consultation meeting.

Emissions from Montana contribute to haze at Glacier National Park in Montana; Yellowstone National Park in Montana, Wyoming, and Idaho; and Theodore Roosevelt National Park in North Dakota. Reasonable progress requires that incremental improvements continue in each planning period as we advance toward the ultimate visibility goal of no human-caused visibility impairment in Class I areas. It is with that in mind that we provide the following recommendations and referenced workbooks to strengthen the SIP. As a reminder, NPS-managed areas are the focus of our review–we do not speak for or represent Class I areas administered by other agencies.

In summary, we request that Montana:

1. Require cost-effective measures to reduce haze-forming pollutants identified through the four-factor analyses in SIP. Our facility-specific recommendations are discussed in subsequent sections.
2. Establish a cost-effectiveness threshold for reasonable progress that is in line with other states.
3. Consider oil and gas emission reduction opportunities in this planning period.
4. Update the record of FLM consultation to include NPS ARD substantive four factor reviews submitted in August and September of 2020.
5. Remove discussion of the wastewater treatment facility at Glacier National Park from the draft SIP.

The Montana draft SIP concludes that no additional emission control measures are needed based on emission reductions from recent source retirements and projected visibility at Class I areas being below their uniform rates of progress (URPs). Montana further highlights minimal visibility benefit and potential economic harm associated with additional controls as reasons not to require controls.

We strongly disagree with this conclusion and rationale as discussed in Section 2.1. Reasonable Progress is a long-term program that depends on the cumulative effects of regional emission reductions. To achieve ongoing reasonable progress in this round of SIP development, we request that Montana require all technically feasible and cost-effective controls identified through the four-factor analyses in the draft SIP.

Four-factor reasonable progress analyses for the following 16 facilities are included in the Montana draft SIP:

Talen Montana LLC - Colstrip

Weyerhaeuser NR - Columbia Falls & Evergreen Facilities
Ash Grove Cement
GCC Trident, LLC
Yellowstone Energy Limited Partnership
Roseburg Forest Products Co.
Colstrip Energy Ltd Partnership
Graymont Western U.S. Inc.
Montana Sulfur & Chemical Co.
ExxonMobil Billings Refinery
CHS Inc. Refinery Laurel
FH Stoltze Land & Lumber Co.
Sidney Sugars Inc.
Phillips 66 Co. - Billings Refinery
Northern Border Pipeline Compressor Station 3

There are several recurring issues with the four-factor analyses that generally the inflated cost of controls. These are discussed in Section 2.2 of this document. Please see Section 3 and supporting calculation worksheets for a detailed review of individual four-factor analyses.

Clean air and clear views are essential to preserving the fundamental purpose of our national parks and ensuring the enjoyment of these special places for the American public both now and in the future. We look forward to continuing working to improve air quality in partnership with Montana in this and future planning periods.

2.1 - Overarching feedback

2.1.1 Long Term Strategy & Control Determinations

The long-term strategy selected by the state does not include additional controls for any of the sources selected for four-factor analysis, despite the fact there are technically feasible, cost-effective control options for several of the emissions units considered. According to the SIP, the state believes that further controls are not needed because: (1) any potential economic costs would be unacceptable; (2) controls would not result in a perceptible visibility benefit during the current planning period; and (3) the projected 2028 visibility is at or below the uniform rate of progress (URP) at Montana's Class I areas. This conclusion is inconsistent with our understanding of the Regional Haze Rule requirements. We offer the following feedback on the state's rationale for its long-term strategy decisions.

2.1.1.1 Economic Considerations

The SIP cites economic considerations as one of the most significant reasons not to require any additional controls. In particular, the state cites increased costs to rate payers and facility closures as reasons not to require controls on any of its EGUs. The SIP also states that facility closures would lead to electrical grid instability. The SIP does not establish a cost-effectiveness threshold for possible controls on any of its facilities, suggesting that the state considers any economic cost would be too high. Regarding EGUs, the state says (p. 167): "Given the shift in electrical generation trends for EGUs and marketplace feasibility for both EGUs and oil and gas, Montana believes any costs imposed on Montana sources must produce a discernible improvement in modeled visibility during this planning period and not have the potential to cause detrimental impacts to Montana's economy, rural communities, and grid stability."

However, the discussion of possible economic consequences from controls on the state's coal-fired electrical generating facilities is largely speculative in nature. While the SIP notes that the number of coal-fired EGUs is trending downward across the country, it does not demonstrate that the application of any possible controls to the state's facilities would necessarily result in additional closures or grid instability. Other states are facing the same trends in coal-fired EGU generation but have selected cost-effectiveness thresholds for their facilities as high as $10,000/ton (Colorado, Oregon). Additional states that have chosen cost-effectiveness thresholds include Arizona ($4,000-$6,000/ton), New Mexico ($7,000/ton), Texas ($5,000/ton), and Washington ($6,250/ton). Our analysis of Montana facilities shows that there are available control options with costs that are below these thresholds and potentially reasonable in this context. In addition, the SIP does not discuss why it would be impossible for facilities other than EGUs to bear any cost from additional controls.

2.1.1.2 Visibility Benefit

In addition to the potential economic costs, the SIP cites the need for discernible visibility benefits from controls to justify the decision to forgo additional control measures in the long-term strategy. However, the Montana does not quantify the cumulative visibility benefit that is necessary or identify the level of improvement that would be considered meaningful. EPA's 2019 guidance acknowledges that the Clean Air Act does not prohibit a state from considering visibility benefit when determining which control measures are needed to make reasonable progress but clarified that visibility benefit should not be the sole factor used to dismiss otherwise reasonable and cost-effective controls. Visibility was not included as one of the four factors that §7491 of the Clean Air Act requires states to consider when determining which controls measures are needed to make reasonable progress. In its July 2021 memo, "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period", EPA addressed the use of visibility benefit when considering potential emissions controls. EPA stated that it is not appropriate to reject cost-effective control measures simply because the impact on visibility is considered insignificant:

> *We have observed that some draft SIPs are using modeled visibility benefits to justify rejecting otherwise cost-effective control measures. It is important that, where applicable, each state considers the magnitude of modeled visibility impacts or benefits in the context of its own contribution to visibility impairment. That is, whether a particular visibility impact or change is "meaningful" should be assessed in the context of the individual state's contribution to visibility impairment, rather than total impairment at a Class I area. As stated in the RHR preamble:*
>
> > *Regional haze is visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. At any given Class I area, hundreds or even thousands of individual sources may contribute to regional haze. Thus, it would not be appropriate for a state to reject a control measure (or measures) because its effect on the RPG is subjectively assessed as not "meaningful."*

2.1.1.3 Uniform Rate of Progress

The SIP also notes that visibility progress at the state's Class I areas is meeting the adjusted URP. The Regional Haze Rule requires that the state determine the URP needed to meet the goal of unimpaired visibility by 2064. However, EPA has clarified that the URP is not a "safe harbor." States should not dismiss otherwise technically feasible, cost-effective controls solely because visibility progress in state's Class I areas is better than the URP. The URP is a planning tool that allows states to evaluate their overall progress toward the goal, but it is not a standard that indicates whether progress is reasonable. It may be that a state's Class I areas are not meeting the URP but the state is still making reasonable progress if it finds by applying four-factor analysis to its sources that there are no technically feasible, cost effective controls to implement. Conversely, it may be that a state's Class I areas are meeting the URP but are still not making reasonable progress if the state rejects technically feasible cost-effective controls because the Class I areas are below the glideslope. As EPA noted in its July 2021 clarification memo:

> *The 2017 RHR preamble and the August 2019 Guidance clearly state that it is not appropriate to use the URP in this way, i.e., as a "safe harbor." The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is "reasonable progress." This concept was explained in the RHR preamble. Therefore, states must select a reasonable number sources and evaluate and determine emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors.*

This memo is consistent with earlier guidance from EPA. As EPA noted in the preamble to the 2017 Regional Haze Rule (82 FR 3099):

> *The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress states must consider the four statutory factors. Treating the URP as a safe harbor would be inconsistent with the statutory requirement that states assess the potential to make further reasonable progress towards natural visibility goal in every implementation period.* ***Even if a state is currently on or below the URP, there may be sources contributing to visibility impairment for which it would be reasonable to apply additional control measures in light of the four factors****. Although it may conversely be the case that no such sources or control measures exist in a particular state with respect to a particular Class I area and implementation period, this should be determined based on a four-factor analysis for a reasonable set of in-state sources that are contributing the most to the visibility impairment that is still occurring at the Class I area.* ***It would bypass the four statutory factors and undermine the fundamental structure and purpose of the reasonable progress analysis to treat the URP as a safe harbor, or as a rigid requirement*** *(emphasis added).*

We request that Montana require all control measures found to be technically feasible and cost-effective through analysis of the four factors specified in the Regional Haze Rule.

2.1.2 Reasonable Progress Cost Evaluations

The "costs of compliance" is the first of the four reasonable progress statutory factors contained in Section 169 of the Clean Air Act.

Overestimation of Costs

In reviewing four-factor analyses presented in the MT draft Reasonable Progress SIP, we identified several re-occurring errors in the cost analyses that generally result in overestimation of costs. As much as possible, we relied upon the most recent versions of EPA's Control Cost Manual (CCM) to identify these errors and inform our calculations. NPS cost analyses for individual MT facilities are described below and documented in the attached calculation spreadsheets.

Some four-factor analyses included sales tax, which we understand is not charged in Montana.

Several four-factor analyses applied a 20% Contingency Cost of Direct and indirect capital costs to all capital cost analyses. The CCM says:

> *The contingency, C, accounts for unexpected costs associated with the fabrication and installation of the absorber and is calculated by multiplying the total direct and indirect costs by a contingency factor (CF). A default value of 10% is typically used for CF.*

In some cases, four-factor analyses include Property Taxes = 1% of TCI. Insurance = 1% of TCI. Administration = 2% of TCI. The CCM says:

> *property taxes and overhead are both assumed to be zero, and insurance costs are assumed to be negligible. Thus, administrative charges and capital recovery are the only components of indirect annual costs estimated in this analysis.*

It is also our understanding that Montana does not assess property taxes on air pollution control equipment.

Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.

EPA's Control Cost Manual (CCM) recommends a scrubber and SCR equipment life of 30 years and use of the current prime interest rate (3.25%) unless a site-specific interest rate is justified. The CCM recommends 20 years for SNCR equipment life.

EPA recently advised Colorado that:

> *Throughout, please provide documentation of the interest rate used to calculate costs of controls and provide the basis for each rate. Where a firm-specific interest rate is available, we recommend that it be used to assess costs. We also recommend that the basis for any firm-specific interest rate be well-documented and justified. If a firm-specific interest rate is not available, then the bank prime rate (currently 3.25%[1]) can be an appropriate estimate of the interest rate. These recommendations are consistent with EPA's Control Cost Manual at Chapter 2, page 15.*

2.1.3 Cost effectiveness thresholds

While Montana has completed the technical work necessary to fulfill the state's analytical obligations under the regional haze provisions, MDEQ has not fully documented the criteria relied upon to make the final reasonable progress determinations, as required under the regional haze (RH) regulations. [1] The Montana SIP evaluated the four statutory factors for sixteen sources but has not identified a cost threshold under which the evaluated controls would be considered reasonable.

It is generally accepted that the cost-effectiveness threshold for Reasonable Progress will be higher as smaller emission units are considered. Other states have set cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR. We recommend that Montana identify a cost threshold for determining whether controls are cost-effective.

2.1.4 Glacier National Park Monitoring Strategy

In section 9.1 of the draft SIP, MDEQ raises a question regarding the representativeness of the GLAC1 Interagency Monitoring of Protected Visual Environments (IMPROVE) monitor. This monitor is used to track the visibility progress of Glacier National Park under the Regional Haze Rule. MDEQ notes that there is a park wastewater treatment plant approximately 500 m north-northwest of the monitor and suggests that it may be contributing to elevated wintertime (November-March) nitrate levels. The SIP includes wind roses in MT Draft SIP Figure 9-4 that were created using data from the Glacier International Airport, which is approximately 20 miles from the monitor. The SIP states that winds on the most impaired days during the wintertime come most frequently from the north-northwest, suggesting that the wastewater treatment plant may be contributing to ammonium nitrate concentrations. Figure 9-4 shows that winds are also from the northeast a significant portion of the time,

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[1] 40 CFR § 51.308 (f)(2)(i): The State *__must include__* in its implementation plan a description of *__the criteria it used__* to determine which sources or groups of sources it evaluated and *__how__* the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. [Emphasis added]

We plotted wind data from the West Glacier horse stables site, AQS site number 30-029-8001, located at latitude 48.5103 degrees north and longitude 113.9969 degrees west. This site is located inside the park boundary very close to the GLAC1 IMPROVE monitoring location, and it is therefore likely to be more representative of winds at the IMPROVE site than the Glacier airport site. Figure 1 below shows hourly winds during the months of November through March for the years 2000-2018. This figure shows that hourly winds are predominantly from the southwest and south, along with a significant contribution from the northeast. This is not surprising, given the site's location near the end of a narrow valley that runs roughly from southwest to northeast. Winds from the north and northwest occur during only a small percentage of the time.

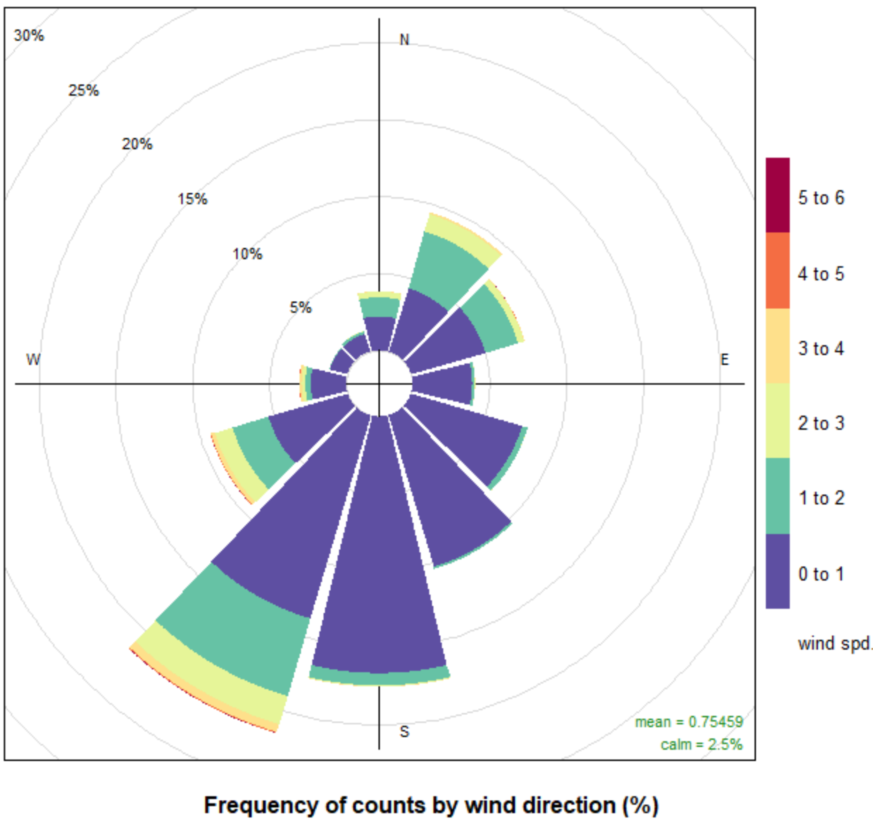

Figure 1. Hourly winds at the West Glacier site during the months of November through March, 2000-2018. Wind speed is shown in meters per second.

Figure 2 shows 24-hour averaged winds, where again winds from the south and southwest predominate.

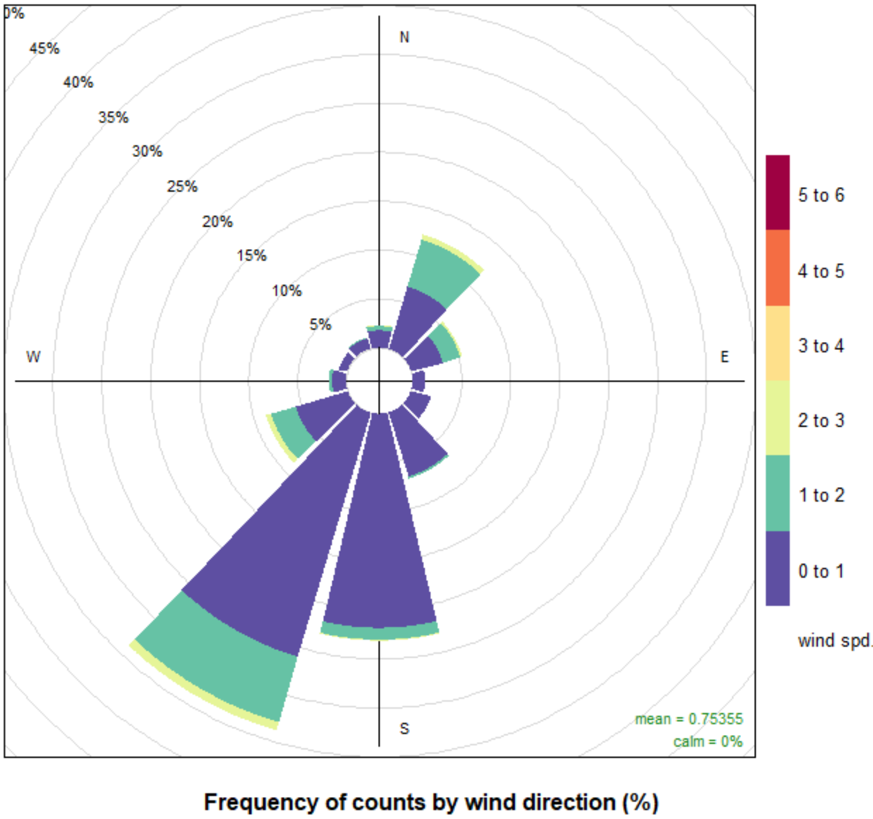

Figure 2. 24-hour average winds at the West Glacier site during the months of November through March, 2000-2018. Wind speed is shown in meters per second.

Figures 3 and 4 show pollution roses for ammonium nitrate concentrations measured at the GLAC1 IMPROVE site on the most impaired days in all months (Figure 3) and just the winter months (Figure 4). Both figures show that the highest concentrations are associated with winds from the southwest, which is the direction of Kalispell and the Whitefish Valley. The wastewater treatment plant is located to the northwest of the monitoring site. Given this, we recommend that MDEQ remove this discussion from the draft SIP and refer any further analysis of potential siting considerations for the GLAC1 monitor to the IMPROVE steering committee.

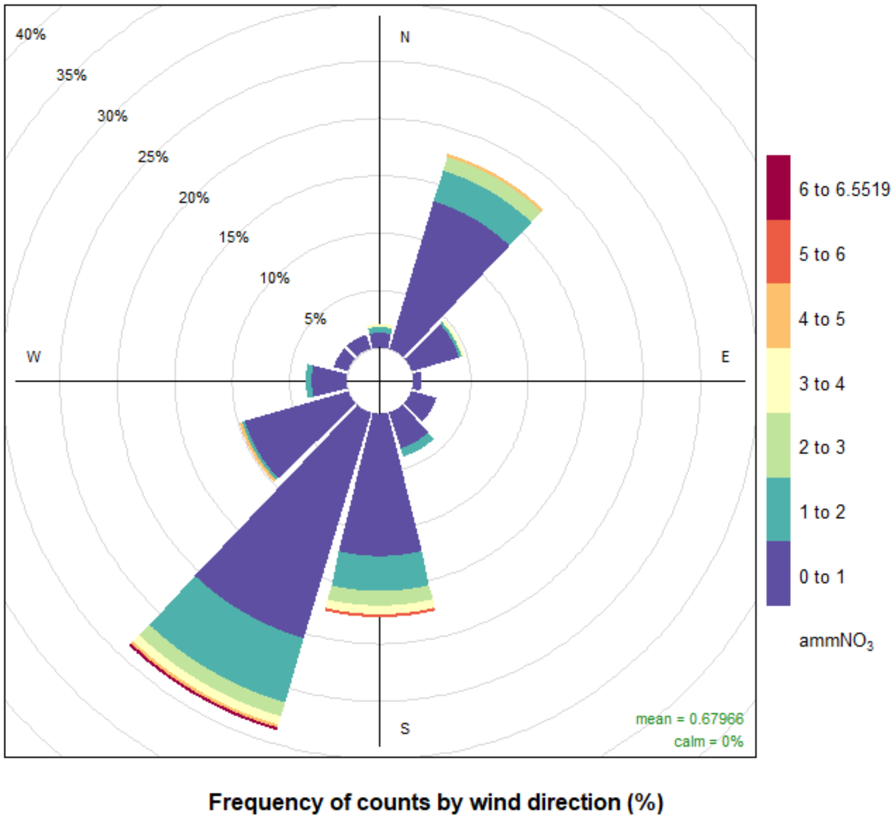

Figure 3. Pollution rose showing ammonium nitrate concentration on the most impaired days during all months, 2000-2018. Ammonium nitrate concentrations are in ug/m3.

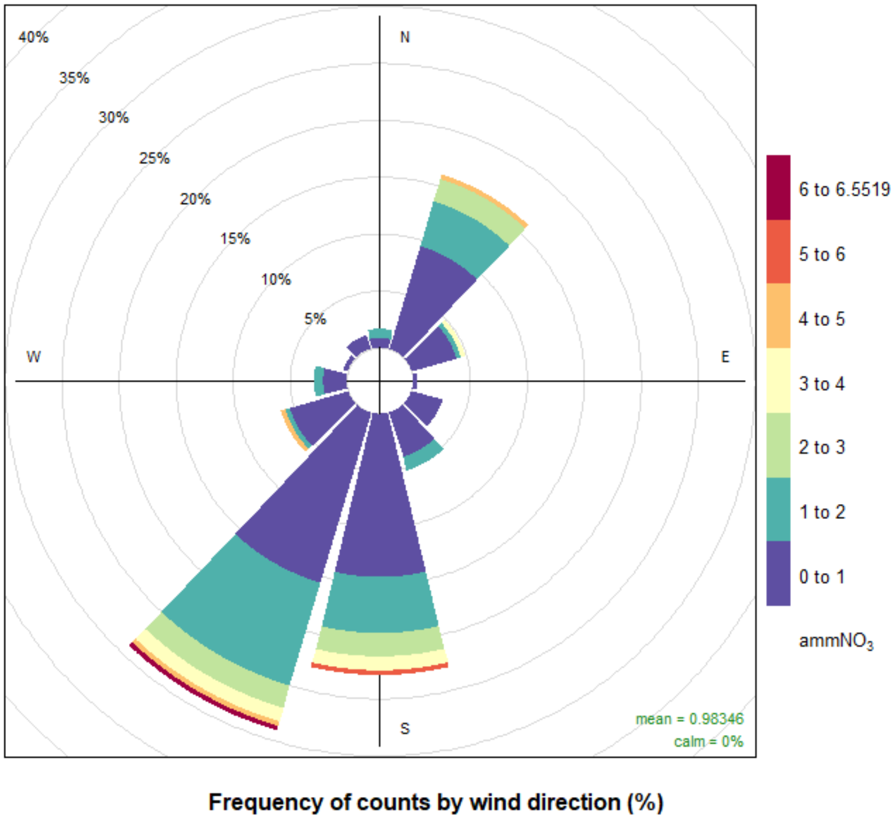

Figure 4. Pollution rose showing ammonium nitrate concentrations on the most impaired days during the winter months (November-March), 2000-2018. Ammonium nitrate concentrations are in ug/m3.

2.2 Specific Review of Four-Factor Analyses

2.2.1 Talen Montana LLC - Colstrip

Summary of NPS Recommendations and Requests for Talen Montana LLC - Colstrip

Our review of the four-factor analysis for the Colstrip Steam Electric Station shows that there are cost-effective controls available to reduce emissions from this facility. Our estimated costs for NO_x reduction for Units 3 and 4 range from $2,121 to $6,521, depending upon the unit, choice of reagent, control technology, and assumed NO_x removal efficiency. Other states have set cost-effectiveness thresholds of $5,000/ton (Texas), $7,000/ton (New Mexico), and $10,000/ton (Colorado and Oregon). Our cost estimates are detailed in the following discussion.

NO_x control cost analysis

The Talen Montana facility consists of two coal-fired electrical generating units, designated as Unit #3 and Unit #4. Both units burn low-sulfur sub-bituminous coal and are each rated at 805 MW gross output. The four-factor analysis prepared by Trinity Consultants considered two post-combustion controls to lower NO_x emissions at Units 3 and 4—selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). To estimate costs, Trinity used the guidance contained in the EPA Pollution Control Cost Manual, 7th edition, released in 2019, and EPA's accompanying spreadsheets. The four-factor analysis provided details of the cost estimates in Appendix A and included only one calculation each for SCR and SNCR. A review of the cost analysis suggests that some of the factors have been overestimated in the four-factor analysis.

We also used EPA's 2019 spreadsheets to calculate costs but performed the calculations for each unit separately, as the operating parameters are slightly different. For the estimated actual annual output in megawatt-hours (MWhs), which is a required input for both the SCR and SNCR calculations, we used an average of the 2018-2019 values reported to EPA's Clean Air Markets database[2] (CAMD) for each unit and adjusted the input values of the net plant heat input rate accordingly. We also made the following adjustments to the inputs:

Trinity used a retrofit factor of 1.3. According to EPA guidance, a retrofit factor of 1 should be used for retrofits of average difficulty. While it may be appropriate in some cases to use a value of up to 1.5, the choice of a value greater than 1 should be documented. The four-factor analysis says that 1.3 was chosen because space is limited at the facility to accommodate reagent preparation equipment and reagent receipt and unloading, but it does not include a detailed analysis explaining why 1.3 is an appropriate value. We therefore used a retrofit factor of 1 rather than 1.3.

As no retirement date has been identified for Units 3 and 4, we used a 20-year equipment lifetime for SNCR and a 30-year equipment lifetime for SCR, as recommended in the EPA Control Cost Manual.

For SCR, we used a controlled NOx emissions rate of 0.04 lb/MMBtu rather than 0.06 lb/MMBtu. According to EPA's Control Cost Manual, Section 4, Chapter 2, controlled emission rates down to 0.04 lb/MMBtu are feasible. A search of the EPA Clean Air markets data for 2019 yielded a

[2] https://ampd.epa.gov/ampd/

number of coal-fired utility boilers (22) with controlled emissions rates at or below 0.05 lb/MMBtu.

For SNCR, the Control Cost Manual says that NOx removal efficiencies for utility boilers vary from 20-60%. The four-factor analysis assumed a reduction to 0.13 lb/MMBtu, which is a removal efficiency of just 13.3%. A removal efficiency of 20%, representing the lower end of the range given in the manual, would result in controlled NOx emissions of 0.12 lb/MMBtu.

For SCR, we selected Method 1 to calculate the catalyst replacement cost.

We estimated costs using both ammonia and urea as the reagent to compare costs.

We selected 2019 as the desired dollar-year and entered the corresponding Chemical Engineering Plant Cost Index (CEPCI) value (607.5).

We used the current (Nov 2021) interest rate of 3.25% in place of 5.5%.

For SNCR we determined we the normalized stoichiometric ratio (NSR) using the guidance in the CCM manual, Section 4, Chapter 1. The equation for estimating the NSR for a system using urea as the reagent is (Equation 1-17):

$$NSR=[(2*NOx_{in} + 0.7)]*\eta_{NOx} /NOx_{in},$$

where NOx_{in} is the NO_x rate into the SNCR, and η_{NOx} is the removal efficiency. We used 0.15 for NOx_{in}, and 0.133 for η_{NOx} (assuming a controlled emissions rate of 0.13 lb/MMBtu), which resulted in an estimated NSR of 0.89. For 20% removal efficiency, this equation gives an estimated NSR of 1.33. We also estimated costs for an SNCR system using ammonia and used the default NSR of 1.05. For SCR, we used the worksheet defaults of 1.05 for an ammonia system and 0.525 for a urea system.

Our estimated costs are shown in Tables 1 and 2 along with Trinity's estimated costs from the four-factor analysis. Note that the four-factor analysis prepared by Trinity did not estimate costs using ammonia as the reagent. Table 3 shows the estimated costs for SNCR assuming a control efficiency of 20% rather than the 13% used in the four-factor analysis. Detailed analyses can be found in the accompanying Excel workbooks; the workbook names begin with "Colstrip_SCR_Unit#" and "Colstrip_SNCR_Unit#."

Table 1. NO_x estimated control cost comparison using urea as reagent.

Control technology	SCR			SNCR		
Analysis performed by:	Trinity	NPS		Trinity	NPS	
Unit	NA	3	4	NA	3	4
Total capital investment	$310,946,279	$260,645,963	$259,708,033	$17,750,899	$14,028,553	$14,014,007
Direct annual costs	$6,347,422	$4,558,194	$4,380,076	$2,937,728	$1,973,536	$1,854,020
Indirect annual costs	$21,414,389	$13,754,309	$13,704,824	$1,493,738	$971,477	$970,470
Total annual costs	$27,761,811	$18,312,503	$18,084,899	$4,431,466	$2,945,013	$2,824,490
Control efficiency (%)	60	73	73	13	13	13
Annual emissions removed (tpy)	2159	2,975	2,773	433	541	504
Average annual cost effectiveness ($/ton)	$12,858	$6,156	$6,521	$10,234	$5,445	$5,602

Table 2.NO_x estimated control cost comparison using ammonia as the reagent (Trinity costs assume urea as reagent).

Control technology	SCR			SNCR		
Analysis performed by:	Trinity	NPS		Trinity	NPS	
Unit	NA	3	4	NA	3	4
Total capital investment	$310,946,279	$260,645,963	$259,708,033	$17,750,899	$14,028,553	$14,014,007
Direct annual costs	$6,347,422	$3,444,098	$3,341,393	$2,937,728	$716,804	$682,366
Indirect annual costs	$21,414,389	$13,754,309	$13,704,824	$1,493,738	$971,477	$970,470
Total annual costs	$27,761,811	$17,198,407	$17,046,217	$4,431,466	$1,688,282	$1,652,836
Control efficiency (%)	60	73	73	13	13	13
Annual emissions removed (tpy)	2159	2,975	2,773	433	541	504
Average annual cost effectiveness ($/ton)	$12,858	$5,782	$6,147	$10,234	$3,122	$3,278

Table 3. Estimated SNCR costs assuming a control efficiency of 20%.

Reagent	Urea		Ammonia	
Unit	3	4	3	4
Total capital investment	$14,416,926	$14,402,190	$14,416,926	$14,402,190
Direct annual costs	$2,851,010	$2,672,513	$722,630	$688,189
Indirect annual costs	$998,372	$997,352	$998,372	$997,352
Total annual costs	$3,849,382	$3,669,865	$1,721,002	$1,685,540
Control efficiency (%)	20	20	20	20
Annual emissions removed (tpy)	811	756	811	756
Average annual cost effectiveness ($/ton)	$4,745	$4,852	$2,121	$2,229

2.2.2 Weyerhaeuser NR - Columbia Falls & Evergreen

Summary of NPS ARD Recommendations and Requests for Weyerhaeuser NR - Columbia Falls & Evergreen

As originally shared with MDEQ in September, 2020, the following provides NPS ARD feedback on the Weyerhaeuser Columbia Falls and Evergreen Facilities four-factor analysis of NO_x Controls for the Riley Stoker Boilers (Columbia Falls and Evergreen), the Line 2 MDF Fiver Dryers (Columbia Falls) and the Line 1 MDF Fiber Dryers (Columbia Falls). In Summary we find that SCR may be cost effective for the Columbia Falls Riley Stoker Boiler and Low NO_x burners may be cost effective for the Line 1 MDF Fiber Dryer (Columbia Falls).

Facility Characteristics

The Riley Stoker Boiler at *Columbia Falls* Operations was installed in 1973. It supplies steam to the refiners and MDF platen press. The boiler is rated at 292 MMBtu/hr and 170,000 pounds per hour (lb/hr) steam. The boiler's average firing rate from 2017 to 2018 was 111 MMBtu/hr.

The Riley Stoker Boiler at the *Evergreen Division* facility was installed in 1971. The boiler is rated at 196 MMBtu/hr and 140,000 lb/hr steam. It supplies steam for process operations such as the dry kilns, the veneer dryers, plywood presses, and the medium density overlay (MDO) press. The boiler's average firing rate from 2017 to 2018 was 96 MMBtu/hr.

The Riley Stoker Boilers at the Columbia Falls Operations and Evergreen Division facility are similar in design. Both are spreader-stoker boilers that combust wood residue, primarily as bark from each facility's log debarking process, and both are load-following boilers, meaning their firing rates are adjusted to meet the changing steam demand of various process operations. Sanderdust burners supplement the hog fuel firing downstream of the spreader-stoker grate in both boilers. The sanderdust burners are also capable of firing natural gas, with a design capacity of approximately 10 percent of the total boiler capacity. Natural gas firing only occurs during startup and rare events of sanderdust shortage. For reasons of similarity in design and operation, the control technology evaluations for both the Columbia Falls and Evergreen units are addressed in this section.

Weyerhaeuser Evergreen Facility NO_x Analysis

Based on the temperature profiles provided in the analysis we agree that SCR and SNCR are not feasible for this facility.

Weyerhaeuser Columbia Falls Facility NO_x Analysis

Weyerhaeuser determined that SNCR was not technically feasible and based on the temperature profiles we agree. Based on the temperature profiles provided for SCR we find that it is likely technically feasible. Weyerhaeuser estimated the cost of SCR at $3,306/ton NO_x. This is well within the range of costs that other states used for the last round of regional haze ($5,000 - $10,000/ton), and below the range that several states have provided for this round of Regional Haze analyses. Additionally, we found several issues/technical deficiencies in Weyerhaeuser's analysis that contribute to the overestimate, which are outlined below.

Columbia Falls Cost Analysis:

Trinity Regional Haze 2nd Planning Period four-factor Analysis for Weyerhaeuser Columbia Falls and Evergreen Facilities (September 2019) tables C-1 and C-2 provide the data used for the Cost analysis for the Columbia Falls Boiler. Weyerhaeuser used the EPA SCR analysis method from June 2015. The issues we identified in this analysis are as follows:

1. The interest rate used was 5.25%, the current interest rate of 3.25% should be used.
2. The equipment life used was 20 years and an equipment life of 25-30 years is more reasonable.
3. The cost of reheat natural gas of $5.53/MMBTU was used but for the Columbia Falls area a cost of $6.00/MMBTU for industrial scale natural gas was identified.

With these adjustments to the Weyerhaeuser SCR cost analysis a cost of $3,113/ton was determined which is well within the range of feasible costs.

Columbia Falls Line 2 MDF Fiber Dryers

SOURCE BACKGROUND LINE 2 MDF FIBER DRYERS:

The Line 2 MDF Dryers at Columbia Falls Operations are direct-contact dryers. The flue gas from the combustion chamber, rated at 85 MMBtu/hr, feeds a two-stage flash tube dryer (the first stage dryer and the second stage dryer). The Line 2 Dryers are equipped with venturi scrubbers, followed by biofilters for particulate and VOC control. The burner that supplies the heat to the dryers is fired with sanderdust from the process and employs staged combustion to limit NO_x formation.

Conclusion:

Based on the potential interaction of the ammonia and the formaldehyde in the urea-formaldehyde resin, and because the Line 2 MDF Fiber Dryers already have staged combustion/low NO_x burners installed, we agree that further controls are not feasible.

Columbia Falls Line 1 MDF fiber dryers

SOURCE BACKGROUND LINE 1 MDF FIBER DRYERS:

The Line 1 MDF Fiber Dryers at the Columbia Falls Operations include a core dryer and a face dryer, each installed with a sanderdust burner with a capacity of 50 MMBtu/hr for each unit. The dryers can process up to 57 tons/hr of bone-dry fiber.

Conclusion:

We agree based on the potential interaction of the ammonia and the formaldehyde in the urea-formaldehyde resin that SCR and SNCR are not feasible for the Line 1 MDF Fiber Dryers at the Columbia Falls facility.

However, we find that staged combustion/low NO_x burners may be economically feasible. As stated before, numerous states in the last regional haze planning period determined that controls at the $5,000–$10,000/ton were economically feasible.

2.2.3 Ash Grove Cement

Summary of NPS Recommendations and Requests for Ash Grove Cement

NPS ARD review of the four-factor analysis conducted for Ash Grove Cement (Ash Grove) finds that there may be additional opportunities available to further control SO_2 and NO_x emissions from this facility.

We recommend that Montana could improve the effectiveness of the draft SIP by setting an SO_2 emission limit that reflects the capability of Ash Grove SO_2 controls. Further, we find that MDEQ analysis of NO_x emission reduction opportunities for Ash Grove is incomplete. A more thorough analysis of the technical feasibility and costs associated with replacing the existing SNCR system with SCR should be conducted. The current SNCR system is achieving 30 to 40% NO_x control while many modern SCR systems achieve better than 80% control and may have additional co-benefits including reduction of mercury emissions.

We recommend that MDEQ require all technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

The Ash Grove facility is located in Montana City, Montana, about 180 km of Yellowstone National Park, a Class I area administered by the NPS.

MDEQ: Ash Grove consists of a long, wet kiln for producing Portland cement. Nearly all the NO_x and SO_2 emissions at the facility are associated with the kiln; therefore, the kiln is the single emitting unit located at Ash Grove requiring a four-factor evaluation. The Ash Grove facility has been in operation since 1963 and is currently owned by CRH but continues to operate under the Ash Grove name.

Ash Grove RepBase and 2028 OTB/OTW Scenarios

MDEQ: Ash Grove selected the two-year average from 2017-2018.as representative of baseline emissions and Montana concurred that this two-year period was reflective of recent normal operation.

Ash Grove also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Ash Grove chose to scale the 2017-2018 representative baseline for future possible market growth and that resulted in the 2028 OTB/OTW scenario being approximately 20 percent higher than the 2017-2018 representative baseline. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 4. MT Draft SIP Table 6-13. Ash Grove RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NO_x	Rep. Baseline SO_2	2028 OTB/OTW NO_x	2028 OTB/OTW SO_2
2017-2018	810.3	101.6	981.5	120.8

SO_2 Evaluation

MDEQ: The current SO_2 control consists of inherent scrubbing of SO_2 by alkali metals including sodium and potassium. In 2012, Ash Grove installed a semi-dry scrubber for SO_2 removal. The current permit limit for SO_2 is limited to 2.0 lb/ton of clinker. The most recent operation has demonstrated that Ash Grove is currently achieving a rate well below the permitted emission rate.

ARD: What is the current SO_2 emission rate in lb/ton of clinker?

MDEQ: Semi-dry scrubbing was determined as BART for SO_2 in the first planning period and has proven to have had significant SO_2 reductions since installation in 2012. Ongoing optimization of the semi-dry scrubbing process will continue in the future. No further four-factor analysis included in this demonstration as Ash Grove is currently using an effective technology to reduce SO_2 at the facility. Ash Grove plans to continue, as required by permit, to operate the semi-dry scrubbing technology.

ARD: Please describe the "Ongoing optimization of the semi-dry scrubbing process" referenced above.

Select Reasonable Progress Control/Final State Recommendations:

MDEQ: MDEQ determined that no additional SO_2 control is required for the second planning period.

ARD: MDEQ could improve the draft SIP by requiring an emission limit that reflects the capability of the SO_2 controls.

NO_x Evaluation

MDEQ: The current NO_x control consists of low-NO_x burner operation and SNCR. Both low NO_x burners and SNCR were selected in the first planning period as BART for NO_x reductions, and were installed in 2014. Combined, these NO_x controls have been operating since 2016 with reduction levels similar to what EPA had predicted in the first planning period. Ash Grove is currently permit-limited to 7.5 lb/ton of clinker and has been achieving an emission rate well below that limit.

Step 1 – Identify All Available Technologies

Both SNCR and SCR are technologies that were determined to be available and were considered in the first planning period. The use of SCR by many industries, including EGUs, has become more common, more so internationally than nationally. In the first planning period, there wasn't much data available on the full cost analysis for incorporating SCR on cement kilns. In this planning period, while there is some more information available on facilities that are working on SCR, the data is largely not available to the public. Therefore, the viability of incorporating SCR, including having an accurate understanding of catalyst life, cost of ammonia/urea injection and actual NO_x reduction levels, is not well-understood.

ARD: SCR is currently being successfully operated on two U.S. cement kilns (Lafarge/Holcim in Joppa, IL and Holcim in Midlothian, TX) as well as several in Europe.

Step 2 – Eliminate Technically Infeasible Options

SELECTIVE CATALYTIC REDUCTION (SCR)

MDEQ: As mentioned above, SCR has seen some continued advancement both internationally and at a few locations within the United States. However, based on the limited use of SCR on cement kilns in the U.S., this technology has been technically eliminated from consideration. There is not enough information available on the technical success or on the actual costs required for construction and operation. Montana has determined that, for this planning period, SCR is infeasible; however, as more facilities analyze and subsequently install SCR, it is likely to become a viable option in future planning periods. A more rigorous SCR evaluation is likely in the third planning period, if the technology has advanced and more information is publicly available to perform a proper assessment.

ARD: MDEQ should show why this available technology is not applicable at Ash Grove Montana City.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: Ash Grove continues to successfully operate the SNCR system achieving NO_x reductions of approximately 30 to 40 percent.

ARD: What is the current NO_x emission rate in lb/ton of clinker?

Step 4 – Evaluate Impacts and Document Results

MDEQ: SNCR continues to operate and achieve the previously established BART limits. There remains some concern around the possibility of a detached plume under certain ambient conditions, as not long after initial start-up, a plume was documented from the facility.

Step 5 – Select Reasonable Progress Control/Final State Recommendations:

MDEQ determined that no additional NO_x control is required for the second planning period.

ARD: The MDEQ analysis lacks a thorough evaluation of replacing the existing SNCR with new SCR.

Conclusions & Recommendations

MDEQ could improve the draft SIP by setting an emission limit that reflects the capability of the SO_2 controls.

The MDEQ analysis lacks a thorough evaluation of replacing the existing SNCR with new SCR.

2.2 4 GCC Trident, LLC

Summary of NPS Recommendations and Requests for GCC Trident, LLC

NPS ARD review of the four-factor analysis conducted for GCC Trident (GCC) finds that there may be additional opportunities available to further control SO_2 and NO_x emissions from this facility.

While SO_2 emissions are quite low, we recommend that Montana could improve the effectiveness of the draft SIP by setting an SO_2 emission limit that reflects the capability of GCC SO_2 controls. Further, we find that MDEQ analysis of NO_x emission reduction opportunities for GCC is incomplete. A more thorough analysis of the technical feasibility and costs associated with replacing the existing SNCR system with SCR should be conducted. The current efficiency of the SNCR system is not documented. Still, SNCR systems are unlikely to approach the efficiency achievable with modern SCR systems which may have additional co-benefits including reduction of mercury emissions.

We recommend that MDEQ require all technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

GCC Trident (GCC) is located in Three Forks, Montana, about 100 km northwest of Yellowstone National Park, a Class I area administered by the NPS.

MDEQ: GCC consists of a long, wet kiln for producing Portland cement. Nearly all NO_x and SO_2 emissions at the facility are associated with the kiln, and therefore the kiln is the single emitting unit located at GCC requiring evaluation. In the first planning period, the plant was often referred to as the Trident or Three Forks Plant. The GCC facility has been in operation since 1972 and is currently owned by Grupo Cementos de Chihuahua GCC.

GCC RepBase and 2028 OTB /OTW Scenarios

MDEQ: GCC selected the two-year average of 2017-2018 as their representative baseline emissions. GCC also selected a future year 2028 OTB/OTW scenario used to calculate the cost per ton of emission reduction achieved from applying controls. GCC chose to scale the 2017-2018 representative baseline for future possible market growth, resulting in the 2028 OTB/OTW scenario being approximately 10 percent higher than the 2017-2018 representative baseline.

GCC provided Montana with a justification for the emissions used in their four-factor analysis and subsequently used in the regional modeling scenarios (RepBase and 2028 OTB/OTW), and Montana concurred that this two-year period was reflective of recent normal operation. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 5. MT Draft SIP Table 6-17. GCC RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NO_x	Rep. Baseline SO_2	2028 OTB/OTW NO_x	2028 OTB/OTW SO_2
2017-2018	1204.8	7.5	1338.0	7.5

SO_2 Evaluation

MDEQ: The emissions of SO_2 at GCC are inherently low due to the chemistry of raw materials used in the kiln therefore, no four-factor analysis was required. SO_2 emissions remain below 10 tpy. There is no reason to believe future emissions of SO_2 will change with the current kiln or similar use of raw materials.

ARD: What is the current SO_2 emission rate in lb/ton of clinker?

Select Reasonable Progress Control

MDEQ determined that no additional SO_2 control is required for the second round of Regional Haze planning.

ARD: MDEQ should set an emission limit that reflects the capability of the SO_2 controls.

NO_x Evaluation

MDEQ: The current NO_x control consists of SNCR, which was selected in the first planning period as BART for NO_x reductions, and was installed in 2017. SNCR controls have been operating since 2016 with reduction levels similar to what was predicted by EPA in the first planning period. GCC is currently permit-limited to 7.6 lb/ton of clinker and has been achieving an emission rate well below that limit. GCC also installed indirect coal firing, providing further reductions in NO_x control beyond what was being achieved with SNCR using ammonia injection. GCC has continued to invest resources in trying to understand their window of operation for NO_x control given the facility is concerned about ammonia slip at the facility. While GCC has been successful at achieving the NO_x limit of 7.6 lb/ton, there remains concern that atmospheric ambient conditions could result in a detached plume from the facility as the result of condensation of ammonium nitrate.

Step 1 – Identify All Available Technologies

MDEQ: The following technologies were determined to be available, SNCR and SCR. Both SNCR and SCR were considered in the first planning period. The use of SCR by many industries, including EGUs, has become more common, more so internationally than nationally. In the first planning period, there wasn't much data available on the full cost analysis for incorporating SCR on cement kilns. In this planning period, while there is some more information available on facilities that are working on SCR, the data is largely not available to the public. Therefore, the viability of incorporating SCR is not well enough understood to have an accurate understanding of catalyst life, cost of ammonia/urea injection and actual NO_x reduction levels. SNCR is in operation at both GCC and Ash Grove. Each of these facilities were selected in the first planning period to install SNCR and did so according to the schedules provided in the BART determinations.

ARD: SCR is currently being successfully operated on two US cement kilns (Lafarge/Holcim in Joppa, IL and Holcim in Midlothian, TX) as well as several in Europe.

Step 2 – Eliminate Technically Infeasible Options

MDEQ: SNCR is currently operating and has successfully reduced emissions at GCC. The second control option remaining is SCR. As mentioned above, SCR has seen some continued advancement both internationally and at a few locations within the United States. However, based on the limited use of SCR on cement kilns in the U.S. this technology has been technically eliminated from consideration. There is not enough information available on the technical success or on the actual costs required for construction and operation. Montana has determined that, for this planning period, SCR is infeasible; however, as more facilities analyze and subsequently install SCR, it is likely to become a viable option in future planning periods. A more rigorous SCR evaluation is likely in the third planning period, if the technology has advanced and more information is publicly available to perform a proper assessment.

ARD: MDEQ should show why this available technology is not applicable at GCC.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: SNCR continues to operate and achieve the previously established BART limits.

ARD: What is the current NO_x emission rate in lb/ton of clinker? How effective is SNCR at GCC?

Step 4 – Evaluate Impacts and Document Results

MDEQ: GCC continues to operate the SNCR system and has demonstrated it can achieve the applicable permit limits. Additionally, the current inherent scrubbing for SO_2 removal proves to be optimal in SO_2 reduction.

Step 5 – Select Reasonable Progress Control

MDEQ determined that no additional NO_x control is required for the second planning period.

ARD: The MDEQ analysis lacks a thorough evaluation of replacing the existing SNCR with new SCR.

Conclusions & Recommendations

- MDEQ could improve the draft SIP by setting an emission limit that reflects the capability of the SO_2 controls.
- The MDEQ analysis lacks a thorough evaluation of replacing the existing SNCR with new SCR.

2.2.5 Yellowstone Energy Limited Partnership

Summary of NPS Recommendations and Requests for Yellowstone Energy Limited Partnership

NPS ARD review of the four-factor analysis conducted for Yellowstone Energy Ltd Partnership (YELP) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from the facility. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The annual average cost effectiveness of adding Spray Dry Absorber/Circulating Dry Scrubber (SDA/CDS) at YELP would be acceptable in the context of the thresholds used by NM, CO, and OR. These technologies could reduce annual SO_2 emissions from YELP by almost 1,650 tons/year.

We find at least two cost effective opportunities for reducing NO_x emissions at YELP. 1) The annual average cost effectiveness of adding SNCR would be acceptable in the context of the thresholds used by TX, NM, CO, and OR and could reduce annual NO_x emissions by over 200 tons/year. 2) The annual average cost effectiveness of adding SCR would be acceptable in the context of the thresholds used by CO and OR and could reduce annual NO_x emissions by almost 350 tons/year.

We recommend that MDEQ require the most effective of the technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

Yellowstone Energy Ltd Partnership (YELP) is located in Billings, Montana, about 190 km northeast of Yellowstone National Park.

MDEQ: YELP consists of two 32.5 MW (gross) circulating fluidized bed (CFB) boilers vented to a single baghouse. The CFBs are the only emitting units at the site that require an evaluation for this demonstration. YELP is fired by petroleum coke and coker gas supplied by the ExxonMobil Billings Refinery as the primary fuels.

ARD: What are the sulfur contents and heating values of the fuels burned?

YELP Rep Base and 2028 OTB/OTW Scenarios

MDEQ: YELP chose to use the average of 2014-2017 emissions as their representative baseline. YELP also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls. YELP chose to use the 2014-2017 representative baseline for the 2028 OTB/OTW scenario.

ARD: Why was 2014–2017 chosen instead of a later period?

MDEQ: YELP provided Montana with a justification for the emissions used in their four-factor analysis and subsequently used in the regional modeling scenarios (RepBase and 2028 OTB/OTW), and Montana concurred this four-year period was reflective of recent normal operation. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 6. MT Draft SIP Table 6-18. YELP RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NO_x	Rep. Baseline SO_2	2028 OTB/OTW NO_x	2028 OTB/OTW SO_2
2014-2017	404.3	1732	404.3	1732

SO_2 Evaluation

MDEQ: YELP currently controls SO_2 emissions using limestone injection. Limestone is injected with the petroleum coke prior to its combustion in the CFB boilers. In the CFB boilers, 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 baghouses. Depending on the fuel fired in the boilers and the total heat input, YELP must control SO_2 from 92% reduction for all boiler operating hours per Montana Operating Permit #OP2650-03[3]. The current limestone injection system is reported to be operating at or near its maximum capacity and increasing limestone injection beyond the current levels may result 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, as those are expected to be significantly more cost-effective.

ARD: We agree. What is the current SO_2 emission rate in lb/mmBtu?

Step 1 – Identify All Available Technologies

MDEQ: As YELP's fuel type (petroleum coke and coker gas), type of boiler (Circulating Fluidized Bed), 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 CFB boiler include: Wet Lime Scrubber, Wet Limestone Scrubber, Dual- Alkali Scrubber, Spray Dry Absorber, Dry Sorbent Injection, Circulating Dry Scrubber, and Hydrated Ash Reinjection.

ARD: We agree that MDEQ has correctly identified available technologies.

Step 2 – Eliminate Technically Infeasible Options

MDEQ: 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. YELP has high efficiency fabric filters 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 CFB boiler equipped with a fabric filter for particulate control. Therefore, the CDS will not be evaluated further.

ARD: CDS systems should not be eliminated from consideration based on "high particulate loading to the unit's particulate control device." According to Sargent & Lundy[4],

> *CDS, can meet removals of 98% or greater over a large range of inlet sulfur concentrations. It should be noted that the lowest SO_2 emission guarantees for a CDS FGD system are 0.04 lb/MMBtu. Recent industry experience has shown that a CDS*

[3] https://deq.mt.gov/Portals/112/Air/AirQuality/Documents/ARMpermits/OP2650-03.pdf

[4] https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-2_sda_fgd_cost_development_methodology.pdf

FGD system has a similar installed cost to a comparable SDA FGD system and has been the technology of choice in last four years.

Please note that in the EPA Control Cost Manual (CCM) cost model for spray dry absorbers and CDS (discussed later), the Base absorber island cost includes an absorber and a new baghouse.

ARD: In making a determination that a control technology is technically infeasible, states must show that a technology is not available, or, if it is available, it is not applicable to the particular situation. CDS is available and has become the technology of choice for dry scrubbing applications. If the rationale for eliminating CDS is increased particulate loading to the existing baghouse, the CCM costing method discussed later addresses that issue. To properly justify elimination of this technology MDEQ must demonstrate that the characteristics of the YELP boiler flue gas are incompatible with the CDS/baghouse option.

MDEQ: The YELP facility has a very limited area to install additional SO_2 controls and manage waste materials. 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 landfill to dispose of scrubber sludge. Due to YELP's limited space requirements, its proximity to the Yellowstone River, and limited water availability for these controls, these technologies are considered technically infeasible and will not be evaluated further.

ARD: We agree.

MDEQ: The three remaining technically feasible control options for the YELP facility were determined to be HAR, SDA, and DSI.

The ability of the existing fabric filter baghouses at YELP 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, a redesigned (new) fabric filter baghouse is included in the cost for each SO_2 control technology.

ARD: We agree that Hydrated Ash Reinjection (HAR), Spray Dry Absorption (SDA), and Dry Sorbent Injection (DSI) are technically feasible if combined with a new baghouse.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: Specific estimated removal efficiencies for HAR, SDA and DSI, are 50 percent for both HAR and DSI and 80 percent for SDA. These approximate control efficiencies are used in determining the cost of compliance.

ARD: We agree with the estimates for HAR and DSI. MDEQ has not explained or justified its estimate of 80% efficiency for SDA. The CCM assumes typical SDA FGD retrofit for removal of 95% of the inlet sulfur which is what we have used in our analysis.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: The cost-effectiveness of each of the technically feasible SO_2 control technologies was estimated based on the methodologies developed and provided in EPA's Air Pollution Control Cost Manual.[5](Control Cost Manual) Each cost analysis is based on the methodology described in the Control Cost Manual, Section 5.2, Chapter 1- Wet Scrubbers for Acid Gas Removal. The cost effectiveness was estimated using the example for Acid Gas Removal because it most closely reflected the control methods being assessed when compared to the other choices. This same methodology was utilized in the first planning period analysis.

ARD: Our cost analysis is based upon the recent update to the CCM.

MDEQ: Equipment and system operations have remained the same at YELP since the first planning period analysis was accepted by the EPA in 2011. Therefore, the first planning period 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.

ARD: The CCM recommends use of the current prime interest rate (3.25% in November 2021) and a 30-year scrubber life.

MDEQ: The 2028 OTB/OTW emissions were used to estimate the cost-effectiveness of the technically feasible control options. All three control options include the cost of installing the designated control option as well as installing an upgraded baghouse system.

Table 7. MT Draft SIP Table 6-19. Estimated Costs of SO_2 Control Options for YELP

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)
Hydrated Ash Reinjection and Baghouses	50%	$35,816,983	$5,796,240	866	866	$6,693
Spray Dry Absorbers and Baghouses	80%	$45,276,409	$7,509,313	1,386	346	$5,420
DSI and Baghouses	50%	$23,446,964	$5,062,421	866	866	$5,846

[5]EPA's Office of Air Quality Planning and Standards (OAQPS) Pollution Cost Control Manual, 6th Edition. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

MDEQ: The costs for additional control of the boiler is considered moderate. Although Montana did not set a threshold for cost-effectiveness for RH planning, Montana is very familiar with cost effectiveness benchmarks prepared under BACT reviews. As previously discussed, the calculated costs above incorporate the additional cost of an upgraded baghouse system. Generally, these costs are higher than BACT level cost per ton values at recently permitted units.

ARD: Our revised costs are shown below:

Table 8. ARD revised Table 6-19. Estimated Costs of SO_2 Control Options for YELP

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)
Hydrated Ash Reinjection and Baghouses	50%	$27,341,019	$3,744,401	866	866	$4,324
Spray Dry Absorbers/CDS and Baghouses	95%	$98,526,746	$8,990,419	1,648	86	$5,456
DSI and Baghouses	50%	$17,797,539	$4,329,224	866	866	$4,999

Factor 2: Time Necessary for Compliance

MDEQ: The addition of HAR, SDA, or DSI would each take approximately the same amount of time. However, as stated previously, the addition of SO_2 controls would likely require complete replacement or major modifications to the existing baghouses. The installation of the new SO_2 controls and baghouses should be staggered to allow one boiler to remain in operation while the retrofits are applied to the other boiler. Bison estimates that the time necessary to complete the modifications to one boiler would be approximately four to six months. A boiler outage of approximately two to three months per boiler would be necessary to perform the installation of both control systems. The total time necessary to install the controls would be approximately one year.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: HAR, SDA and DSI installed systems require electricity to operate. SDA, DSI, and HAR systems have been estimated to consume 0.1% to 0.5% of total plant generation. These control systems being analyzed use electricity primarily for the ID fan, lime/limestone handling equipment and baghouse blowers. The addition of the SO_2 controls would result in increased ash production at the YELP 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 YELP approximately $2,300,000 year at the current ash value and production rates (approximately 170,000 tons of ash/year). The loss of this market would also result in YELP having to dispose of the ash at its current landfill, which is approximately 80 miles from the YELP plant. YELP currently pays a fixed fee of approximately $500,000 a year to manage this landfill. YELP incurs a fee of $3.56/ton on ash taken to the pit that is in excess of 140,000 tons/year. At its current production and ash disposal costs, this would result in an increased cost to YELP of approximately $96,000/year. The total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $2,400,000/year.

ARD: MDEQ suggests that 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. Evidence to support this possibility is needed. Additional ash may lead to increased sales and revenues.

The attached Excel workbook uses the new CCM methods. We estimate that a spray dry absorber (or CDS) and new baghouse could be added to reduce SO_2 by over 1,600 tons/year at less than $5,500/ton.

MDEQ: Another potential impact would be to mercury emissions. YELP has recently determined that mercury content in its limestone feed has contributed to a violation of the federal Mercury Air Toxics Standard. Additional use of limestone (which is included in the SO_2 controls listed above) would trigger added costs and control to address potential mercury emissions resulting from that limestone.

ARD: How is this problem being addressed?

Factor 4: Remaining Useful Life

MDEQ: The CFB boilers at YELP are not planned for retirement at this time. The remaining useful life of the sources is assumed to be 20 years.

ARD: Our analysis assumes that the boilers and any additional scrubbers would have a useful life of 30 years. MDEQ's use of a shorter (20-year) remaining useful life should rely on a federally enforceable permit condition.

Step 5 – Select Reasonable Progress Control

MDEQ: The costs for retrofit are considered moderate and the annual SO_2 emissions remain over 1,700 tpy with no known additional reductions to have occurred at the facility; however, Montana has determined that no additional SO_2 controls are required. Montana concurs with the YELP prepared and submitted four-factor analysis that the current limestone technology in place at YELP is providing an effective control of SO_2.

ARD: We arrived at similar cost estimates for SDA/CDS.

NO_x Evaluation

MDEQ: During the first planning period analysis, YELP 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 CFBs with NO_x controls. Their expertise was utilized to develop as close to an estimate of each control technology as possible.

Again, equipment and system operations have remained the same at YELP since the first planning period analysis was accepted by the EPA in 2011. Therefore, the first planning period 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.

ARD: The CCM recommends use of the current (3.25% as of November 2021) prime interest rate.

MDEQ: The average of YELP NO_2 emissions from 2014 to 2017 was used to estimate the cost-effectiveness of the technically feasible control options. Both control options include the cost of installing the designated control option but do not account for the cost of facility downtime.

YELP currently controls NO_x emissions using good combustion practices in the CFB boilers. 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 CFB boiler already reduces the formation of thermal NO_x emissions in the range of 50% or more compared to other boiler designs. YELP must meet emission limits of 0.400 lb/MMBtu and 319.0 pounds per hour per #OP2650-02.

ARD: What is the current NO_x emission rate in lb/mmBtu?

Step 1 – Identify All Available Technologies

MDEQ: As YELP is currently using boiler design to control NO_x 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 (SNCR).

ARD: We agree with MDEQ that 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 (SNCR).

Step 2 – Eliminate Technically Infeasible Options

MDEQ: 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 CFB boiler that has inherently low combustion temperatures and relatively lower thermal NO_x. Further, a CFB 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.

SCR and SNCR are considered technically feasible options for NO_x control of the YELP boilers for the purpose of this analysis. However, both control technologies have difficulties in design, construction, and implementation. Most notably, SCR control creates a high risk of causing superheater damage due to the interaction of vanadium in petroleum coke and the SCR catalyst. Likewise, the YELP facility has a very limited area to install additional controls and manage waste materials. These space limitations also apply to the potential installation of SCR and SNCR. However, both control technologies were still evaluated. The technical limitations are described further in the energy and non-air environmental compliance section (Factor 3) and the summary.

ARD: We agree with MDEQ that the post-combustion controls that are technically feasible in this application are SCR and SNCR.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: The cost-effectiveness of the technically feasible NO_x control technologies was estimated using the first planning period total capital and operating cost estimates developed by Metso, the Harris Group, and EPA's Air Pollution Control Cost Manual, 6th Edition. The newly published 2019 control cost manual analyses for SCR and SNCR were not utilized in this demonstration, since the YELP boilers are not accurately represented within the spreadsheet calculations. The YELP boilers are dual purpose and create steam for the ExxonMobil Billings Refinery as well as power generation. It is difficult to provide accurate input data for the YELP boilers within the utility or industrial functions of the spreadsheet. The 2019 calculations also do not provide representative fuel characteristics for the utilization of petroleum coke and coker gas at YELP. The Metso and Harris Group cost estimates were provided specifically for the YELP facility and provide the most reasonable estimate for this stage of planning. Therefore, the 2011 analyses were revised utilizing the vendor specific cost estimates.

ARD: We applied the CCM methods but defer to the site-specific estimated provided by Metso.

SELECTIVE CATALYTIC REDUCTION (SCR)

MDEQ: Theoretically, SCR systems can be designed for NO_x removal efficiencies up close to 100 percent. In practice, new 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 CFB boiler technology). The outlet concentration from SCR on a utility boiler is rarely less than 0.04 pounds per MMBtu (lb/MMBtu)[6]. Based on that limitation, which is particularly applicable to a retrofit unit, the proposed reduction associated with SCR for the YELP boilers is 80% as provided by vendor data detailed in Factor 1.

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.

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

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

MDEQ: 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 YELP 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 due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers. The YELP boilers combine for 65 MW and therefore are considered small boilers.

ARD: We agree with the average reduction of 50% used in the SNCR cost efficiency calculations (because that was selected/determined to be feasible in the vendor quote) and the proposed 50% reduction associated with SCR for the YELP (as provided by vendor data).

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: The cost-effectiveness of the technically feasible NO_x control technologies was estimated using the first planning period total capital and operating cost estimates developed by Metso, the Harris Group, and by the Control Cost Manual. The Metso and Harris Group cost estimates were provided specifically for the YELP 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 YELP since the first planning period analysis was accepted by the EPA in 2011. The first planning period 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 Control Cost Manual.

The results of the analysis are summarized below. Both control options include the cost of installing the designated control option but do not account for the cost of facility downtime.

Table 9. MT Draft SIP Table 6-20. Estimated Costs of NO2 Control Options for YELP

NO_x Control Option	% Control	Total Capital Investment	Total Annual Cost	Annual Emission Reduction (tpy)	Annual Emissions After Control (tpy)	Average Annual Cost Effectiveness ($/ton)
Selective Catalytic Reduction	80%	$32,460,400	$4,153,623	323	81	$12,841
Selective Non-Catalytic Reduction	50%	$1,020,800	$597,303	202	202	$2,954

The costs for additional NO_x control of the boilers vary and are 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 YELP 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 investment would be required from YELP 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 and describes YELP's operating relationship with the ExxonMobil Billings Refinery. Lost revenue due to facility downtime would increase the total annual costs associated with adding on emissions controls.

ARD: The cost-effectiveness of the technically feasible NO_x control technologies was estimated using the first planning period total capital and operating cost estimates developed by Metso, the Harris Group, and EPA's Air Pollution Control Cost Manual, 6th Edition. Bison contends that the 2019 control cost manual analyses for SCR and SNCR should not be utilized since the YELP boilers are not accurately represented within the spreadsheet calculations because they do not provide representative fuel characteristics for the utilization of petroleum coke and coker gas at YELP. Instead, Bison contends that the Metso and Harris Group cost estimates provided specifically for the YELP facility provide the most reasonable estimate for this stage of planning. Therefore, Bison revised the 2011 analyses utilizing the vendor-specific cost estimates.

We have reviewed the Metso and Harris facility-specific vendor costs and agree that they are more accurate than generic facility calculations from EPA's Control Cost Manual. We have also reviewed the cost analyses for SCR and, although we believe those costs have been overestimated, even when corrections are made, SCR would still cost over $8,500/ton.

Because the equipment and system operations have remained the same at YELP since the first planning period, the first planning period cost analysis for NO_x was updated by Bison 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. We have updated the 2011 Metso analysis by using the CEPCI instead of the CPI to account for inflation, and applied the current 3.25% prime interest rate, instead of the 5.5% rate used by Bison.

Our revised costs are shown below:

Table 10. ARD revised MT Draft SIP Table 6-20. Estimated Costs of NO2 Control Options for YELP

NO_x Control Option	**% Control**	**Total Capital Investment**	**Total Annual Cost**	**Annual Emission Reduction (tpy)**	**Annual Emissions After Control (tpy)**	**Average Annual Cost-Effectiveness ($/ton)**
Selective Catalytic Reduction	80%	$28,674,983	$2,750,992	323	81	$8,505
Selective Non-Catalytic Reduction	50%	$901,214	$515,038	202	202	$2,548

ARD: Bison has overstated the uncertainty involved in the cost estimation process:

> *The costs for additional NO_x control of the boilers vary and are 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 YELP 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 investment would be required from YELP to determine a more refined cost estimate.*

The Metso cost analysis appears to be more detailed than typical cost analyses developed for this level of review. If YELP believes that the Metso estimates are inaccurate, it can conduct the "more refined cost estimate" mentioned by Bison.

Bison has also exaggerated the costs of adding SNCR:

> *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 and describes YELP's operating relationship with the ExxonMobil Billings Refinery. Lost revenue*

due to facility downtime would increase the total annual costs associated with adding on emissions controls.

On the contrary, the Metso report clearly states that:

> *The tie-in can be made during the normal annual outage. The majority of the system can be installed with boilers on-line. The nozzles would be installed during the annual outage.*

We found the Metso report sufficiently detailed for this analysis, as is demonstrated below.

[beginning of the Metso excerpt]

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 boilers, and injection nozzles at the cyclone inlets for the boilers.

There are two boilers at this facility. A single line will be routed from the forwarding system to the elevation of the cyclone inlet ducts of the two boilers. The line will branch into two lines at this elevation. Each branch line will have a control valve that will meter the required flow to the specific boiler. The line downstream of each control valve will branch again to feed two distribution or metering panels. A distribution panel will be located at each of two cyclone inlet ducts on each boiler. The metering skids will be used to bias ammonia flow to each of the four nozzles on each cyclone inlet duct.

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.

LOCATION AND INSTALLATION CONSIDERATIONS

The distribution panels and injection nozzles are located near the cyclone inlet ducts. The injection nozzles penetrate and mount to the cyclone inlet ducts. The nozzles are used to inject ammonia into the duct, while distributing the ammonia across as much as the duct as practical. 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. The ammonia is sprayed upstream of the cyclones on the CFB. The cyclones promote further mixing of the ammonia and the flue gas because of flue gas cyclonic action, direction change, and mixing. Higher reduction rates are achievable on CFBs than for BFBs, and other boiler types because of this optimum spray location and cyclonic mixing. While it may be possible to capture more NOx on a CFB, the standard guaranteed reduction rates are in the 50% range in order to limit slip to 10 ppm.

CAPITAL COSTS AND DOWNTIME

There are two boilers at YELP. A common ammonia system tank and delivery system will be utilized for both boilers. The ammonia tank and forwarding system is the bulk of the cost for supply and installation. The rest of the system consists of supply and installation of small bore piping, distribution skids, and injection nozzles. The majority of the piping is installed for the SNCR for the first unit. The pipe for the second unit branches off at the upper elevation for distribution of ammonia to the second unit. There is a minimal incremental cost for the equipment and installation of SNCR technology for the second unit because of this. The incremental cost is limited to installation of some small bore piping, a control valve, two additional distribution panels, tubing, and nozzles into the cyclones. The installed estimate for the SNCR system is $880,000. This is the installed cost for SNCR technology for NO_x control for both units. Control technologies are often evaluated based on $/kw basis. The gross electrical generation for each boiler is 32.5 MW. The estimated cost for SNCR capital costs (supply and installation) is $14/kw.

OPERATING AND MAINTENANCE CONSIDERATIONS

The O&M costs are estimated to be approximately $220,000 per unit. Most of this is the cost of the ammonia. Ammonia consumption is $203,000 per unit based on $196/delivered ton. Maintenance of the ammonia system and nozzles should average $10,000-15,000 for each unit.

[end of Metso excerpt]

Factor 2: Time Necessary for Compliance

MDEQ: Due to the complexity of the existing infrastructure and severely 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.

ARD: According to the Metso report:

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

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: 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 CFB boiler leading to lost boiler efficiency and, thus, a loss of power production. Along with the power loss, YELP would be subject to the additional cost of reheating the exhaust gas, which is an inefficient use of energy and additional fuel.

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 also contribute to equipment fouling due to ammonia bisulfate formation. Equipment fouling can reduce unit efficiency and increase flue gas velocities. Additionally, the ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste. 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. The presence of vanadium in the petroleum coke fuel has also led to reduced catalyst life on SCR units. A detailed assessment of catalyst life cost would require further analysis by a catalyst vendor.

Fouling of petroleum coke-fired units occurs on superheater surfaces. The superheater is upstream of this SCR. The fouling will likely cause plugging and blinding of the SCR catalyst when it breaks loose from the superheater surfaces. This will increase maintenance costs at this facility and subject the unit to increased downtime.

ARD: MDEQ says: "The energy impacts from an SNCR are minimal and an SNCR does not cause a loss of power output from the facility." MDEQ also states that "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…" There is no evidence that these risks and impacts would be any greater than for other similar facilities employing SNCR. According to the Metso report: "SNCRs are the primary method of NO_x 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." We concur that addition of SNCR would have no adverse energy or non-air quality environmental impacts.

Factor 4: Remaining Useful Life

MDEQ: As previously stated in the SO_2 analysis, YELP is not planned for retirement at this time. A remaining useful life of the sources is assumed to be 20 years.

Step 5 – Select Reasonable Progress Control/Final State Recommendations:

MDEQ has determined that, although "the costs for the technologies evaluated for NO_x reductions are considered moderate. No additional NO_x control is required for the second planning period. NO_x emissions remain significant at nearly 400 tpy, and future planning periods will continue to focus on whether the estimated costs are low enough to justify new controls."

ARD: Taken at face value, the cost effectiveness of adding SNCR as estimated by Metso/Bison/MDEQ would be less than $3,000/ton. This "moderate" [MDEQ] cost is well below the values used by EPA and many states. When we revised the Bison estimates to apply the CEPCI (instead of the CPI) and the current 3.25% prime interest rate (instead of 5.5%) we estimate the cost-effectiveness of SNCR at less than $2,600/ton.

Conclusions & Recommendations

- We are seeing cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The annual average cost effectiveness of adding SDA/CDS at YELP would be acceptable in the context of the thresholds used by NM, CO, and OR and could reduce annual emissions by almost 1,650 tpy.
- The annual average cost effectiveness of adding SCR would be acceptable in the context of the thresholds used by CO and OR and could reduce annual emissions by almost 350 tons/year.
- The annual average cost effectiveness of adding SNCR would be acceptable in the context of the thresholds used by TX, NM, CO, and OR and could reduce annual emissions by over 200 tons/year.

- Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.6 Roseburg Forest Products Co.

Summary of NPS Recommendations and Requests for Roseburg Forest Products Co.

NPS ARD review of the four-factor analysis conducted for Roseburg Forest Products (Roseburg) finds that SO2 emissions are quite low and do not warrant further evaluation. However, we also find that NO_x emission reduction opportunities for Roseburg warrant further evaluation. Based on reviewing NO_x emission control analyses from similar facilities, we can advise that there are technically feasible opportunities to control NO_x emissions from the ROEMMC burner at Roseburg. We recommend that MDEQ complete or require a full four-factor analysis including the costs of replacing or controlling NO_x emissions from the Roseburg ROEMMC burner. The age of the burner should not be considered in this analysis unless Roseburg accepts a federally enforceable retirement date for this emission unit.

We recommend that MDEQ require the most effective technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

Roseburg Forest Products (Roseburg) is located in Missoula, Montana, about 155 km south of Glacier National Park, a Class I area administered by the NPS.

MDEQ: Roseburg consists of three emitting units that are each evaluated in this updated analysis. The three emitting units are related to combustion devices which provide heat for the particleboard manufacturing production line as described below.

The facility has historically had two production lines, one with a multi-platen batch press (Line 1) and one with a continuous press (Line 2). Roseburg went through a Line 1 modernization project to increase the production efficiency of the facility. As part of the Line 1 modernization project, the facility went from the historic two-line production configuration, to a single production line configuration. Line 1 historically consisted of four dryers (dryer 100 through dryer 103, referred to by the facility as dryers 1 through 4) which dry both face and core material. All four dryers continue to exhaust through a single, common stack.

The Line 2 production line had consisted of two dryers, dryer 200 and dryer 201 (referred to as dryers 5 and 6). Dryer 5 was reconfigured to supply the Line 1 storage bins, and Dryer 6 was removed from service. Dryer 5 exhausts to atmosphere through a dedicated stack.

A pre-dryer is used to reduce the moisture of green wood materials received at the facility and was unchanged during the Line 1 modernization project. Heat for the pre-dryer is provided by a 45 MMBtu/hr SolaGen sanderdust burner.

Heat input for the five final dryers associated with Line 1 (post Line 1 modernization project; dryers 1 through 5) is provided by the combined exhaust of a 50 MMBtu/hr ROEMMC sanderdust burner and a sanderdust-fired Babcock & Wilcox low NO_x suspension-type boiler, which also provides steam for facility processes. The ROEMMC burner was installed in 1979. The sole purpose of this burner is to provide heat input for the final dryers. The ROEMMC burner is currently 41 years old. The newer Babcock & Wilcox boiler was installed in 2015. It was subsequently upgraded, also in 2015, with a low-NO_x burner and resulted in a decrease in heat input rating from 55 MMBtu/hr to the current 52 MMBtu/hr. Unlike the other facility sanderdust burners, the boiler serves the function of producing steam for facility processes in addition to providing heat input to the final dryers. A third burner, the SolaGen, provides heat input to the pre-dryer. The SolaGen burner was installed in 2006. For purposes of clarity, the three units are identified as ROEMMC, Babcock boiler, and SolaGen.

A horizontal manifold connects the boiler and ROEMMC burner exhaust stacks to provide combined exhaust to the five final dryers for the single manufacturing Line 1. Both the Babcock boiler and ROEMMC burner stacks allow exhaust to be diverted to atmosphere in the event of an emergency or upset condition. Line 1 dryers (Dryers 1-4) exhaust to multi-clones for particulate control. The multi-clone exhaust is combined and released from a single Line 1 dryer stack. Dryer 5 exhausts to a multi-clone, which emits to atmosphere.

The SolaGen burner exhaust is utilized to dry green furnish materials in the pre-dryer. Green materials are typically about 50% moisture, so the primary purpose of the pre-dryer is to reduce the moisture by approximately 80% or more so that the pre-dried material is suitable for final drying in the Line 1 dryers. The SolaGen burner is equipped with a low NO_x burner and flue gas reinjection to reduce NO_x emissions. Exhaust from the pre-dryer is controlled by a cyclone, a wet electrostatic precipitator (WESP) and a regenerative thermal oxidizer (RTO). These controls significantly reduce emissions of particulate matter (PM).

Roseburg RepBase and 2028 OTB/OTW Scenarios

MDEQ: Roseburg selected the four-year average from 2014-2017 for their representative baseline and Montana concurred that this four-year period was reflective of recent normal operation. Roseburg also selected a 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

MDEQ: Roseburg chose to use the 2014-2017 representative baseline for the 2028 OTB/OTW scenario.

ARD: What were 2018–2020 emissions?

MDEQ: Roseburg was not asked to conduct an analysis for SO_2 reductions as their baseline emissions for SO_2, like most wood products facilities, are very low.

ARD: We agree.

MDEQ: Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 11. MT Draft SIP Table 6-21. Roseburg RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NO_x	Rep. Baseline SO_2	2028 OTB/OTW NO_x	2028 OTB/OTW SO_2
2014-2017	299.3	3.3	299.3	3.3

NO_x Evaluation

MDEQ: NO_x emission controls have been analyzed for the Babcock boiler, ROEMMC, and SolaGen sanderdust combustion devices. Currently there are no NO_x add-on emission controls on these devices. However, the SolaGen burner was installed in 2006 with a low-NO_x burner and flue gas recirculation, and the Babcock boiler was upgraded with a low-NO_x burner in 2015. Each of the units can be fired upon natural gas and/or sanderdust, although NO_x emissions increase significantly from the firing of sanderdust.

Step 1 – Identify All Available Technologies

MDEQ: NO_x control technologies identified include SNCR, SCR, RSCR and low NO_x burners.

Selective Non-Catalytic Reduction (SNCR)

MDEQ: SNCR systems have been widely employed for biomass combustion systems globally. SNCR is relatively simple because it utilizes the combustion chamber as the control device reactor, achieving control efficiencies of 30-70%.

Selective Catalytic Reduction (SCR)

MDEQ: Unlike SNCR, SCR reduces NO_x emissions with ammonia in the presence of a catalyst. The major advantages of this are the higher control efficiency (70%-90%) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending upon the catalyst selected). SCR is widely used for combustion processes where the type of fuel produces a relatively clean combustion gas, such as natural gas turbines.

SCR is not widely used with wood-fired combustion units due to the amount of particulate that is generated by combustion of wood. The particulate, if not removed completely, can cause plugging in the catalyst and coat the catalyst such that the surface area for reaction is reduced. Another challenge with wood-fired combustion is the presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels. Sodium and potassium will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic.

To prevent the plugging, blinding, and/or poisoning of the SCR catalyst, it is necessary to first remove particulate from the exhaust gases. It is not considered technically feasible to place an SCR unit upstream of the particulate control device in a wood-fired boiler or burner application due to the potential for decreasing the useful life of the catalyst and decreasing the control efficiency, which can happen relatively quickly. Use of SCR on a wood-fired boiler or burner application requires a high temperature particulate control device so that the downstream temperature is still in the range of 400°F to 800°F, which is necessary for the reduction of NO_x in the presence of the catalyst. In situations where NO_x

emissions are being controlled downstream of a dryer where the outlet temperature is well below 200°F, the catalyst is essentially ineffective at reducing emissions.

RSCR

MDEQ: RSCR is a commercially available add-on control technology by Babcock Power Inc. that combines the technology of a regenerative thermal oxidizer device and SCR. An RSCR unit is approximately 95% efficient at thermal recovery. The exhaust is heated to a temperature in the range optimal for catalytic reduction (600°F to 800°F) prior to entering an SCR unit. These systems have been shown to reduce NO_x emissions to less than 0.075 lbs/MMBtu and can achieve emission reductions to as low as 0.05 lbs/MMBtu.

Low NO_x Burner

MDEQ: Low NO_x burners are a viable technology for many fuels including sanderdust and gasified biomass. Generally, staged combustion and sub-stoichiometric conditions can be used to limit the amount of NO_x formation. The SolaGen burner and the Babcock boiler at the Missoula facility both already utilize low NO_x burners.

Step 2 – Eliminate Technically Infeasible Options

MDEQ: SNCR relies on the injection of ammonia in the combustion chamber of the sanderdust fired devices. The ROEMMC and SolaGen burners are not believed to have the residence time needed at the critical temperatures for the reaction to take place. It is unknown whether sufficient residence time would occur in the Babcock boiler combustion zone. Because these combustion units provide exhaust to the dryers, there is a great deal of concern about the impact of ammonia on the wood furnish. In making particleboard, the wood furnish is combined with a formaldehyde-based resin. Ammonia acts as a scavenger of free formaldehyde, which could have some effect on resin curing if ammonia is trapped within the furnish during forming.

Another concern is that ammonia can darken or blacken certain wood species. It is unknown what impact ammonia would have on the wood species being used by Roseburg for the period of time it would be exposed, the concentrations of excess ammonia, and at the elevated temperatures that occur in the dryers. As part of developing the 2011 reasonable progress analysis, the National Council of Air and Stream Improvement was contacted to inquire as to whether they were aware of any installations where ammonia was injected upstream of a wood particle dryer. No instances where ammonia injection was conducted upstream of a wood particle dryer were identified.

Due to the uncertain impact that ammonia could have on wood furnish and resin curing, SNCR is not considered an applicable technology with proven feasibility for any of the sanderdust combustion devices due to their location upstream of the wood particle dryers.

ARD: We agree.

MDEQ: Where wood combustion is concerned, SCR requires a clean exhaust stream with temperatures between 400°F and 800°F. PM in the exhaust from wood combustion can poison, blind, or plug catalyst beds very rapidly in certain conditions. As a result, it is industry practice to have a good PM control device upstream of the catalyst bed. For the Backcock boiler and ROEMMC burner at the Missoula facility, there is not sufficient room for particulate controls and a catalyst bed upstream of the particle dryers. Additionally, the exhaust temperature exiting the catalyst bed would be significantly cooler, which would provide less heat to the dryers. The SCR unit could be located downstream of the dryers and particulate controls, but the dryer exhaust temperature is well below 400°F. With regard to the SolaGen burner, the same concerns are valid.

Additionally, the location of an SCR unit upstream of any of the dryers would result in ammonia slip into the dryers. The presence of ammonia slip into the dryers could have unintended consequences for the wood furnish, thereby affecting the manufacturing process. For these reasons, SCR is not considered an applicable technology with proven feasibility for any of the sanderdust combustion devices.

The RSCR control device was assessed in the 2011 reasonable progress analysis. In that assessment, issues with technical feasibility of the RSCR on wood combustion units were raised. These concerns were based on direct comments from the RSCR vendor and were specific to catalyst performance. The vendor would not guarantee the catalyst life due to potential blinding. The 2011 reasonable progress analysis states:

> *"It should be noted that the RSCR vendor would not guarantee catalyst life beyond three years due to the potential for poisoning and blinding associated with the combustion products of wood fuels."*

Additionally, the 2011 reasonable progress analysis describes the challenges encountered with trying to obtain a quote from the RSCR vendor. RSCR units were being heavily marketed at the time but concerns across the air pollution control industry relating to the catalyst performance, unit cost, and thermal efficiency inhibited widespread adoption.

The work related to the 2011 reasonable progress analysis was conducted almost 10 years ago. In that time, one might expect that, if technical feasibility issues had been addressed, then RSCR units would appear in the RBLC. The RBLC was queried for any BACT, RACT or LAER determinations in the past 10 years for NO_x emissions resulting from combustion of wood, wood products, or biomass. This RBLC search criteria were left purposely broad to gather as many NO_x determinations as possible.

No determinations made in the past 10 years for control of NO_x emissions from units combusting wood, wood products, or biomass included an RSCR unit. This supports a determination that the RSCR unit is not feasible for wood combustion units. Based on the comments from the RSCR vendor relating to catalyst poisoning, and the fact that RSCR units do not appear in the RBLC search for NO_x controls, the RSCR unit is deemed to be technically infeasible.

ARD: We disagree. Oregon has included this provision in its draft SIP:

> *If a new power purchase agreement is signed, within 180 days of notifying DEQ, Biomass One shall submit a complete application for installation of NO_x reduction technology that includes SCR on the North and South Boiler or demonstrates SCR is technically infeasible or presents other unacceptable energy or non-air quality impacts.*

The excerpt below is from the New Hampshire draft Regional Haze SIP:

__Burgess BioPower__: The biomass unit at this facility was subject to NNSR for NO_x at the time of their initial permitting; hence, the NO_x limit was established as the LAER[7] based limit. The NO_x limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NO_x/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for SO_2 at the time of its initial permitting in 2010; hence, the SO_2 limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. SO_2/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the SO_2 BACT. Sorbent injection was installed for acid gas control but is not used to control SO_2 emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs SO_2/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for SO_2. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NO_x and SO_2. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

MDEQ: A low-NO_x burner technology is already in use for the SolaGen sanderdust burner as well as the Babcock boiler. The ROEMMC burner does not have low-NO_x burner technology and could be a candidate for an upgrade if it were a much newer unit. It was installed in 1979 and a retrofit to low NO_x burner technology is not considered cost effective. If the ROEMMC burner is replaced it would include low-NO_x burner technology that would provide NO_x emission reductions. A cost analysis was not conducted because of the age of the unit.

ARD: In the absence of a federally-enforceable shut-down condition, a cost-effectiveness analysis should be conducted.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: Since there were no NO_x control devices deemed technically feasible, control effectiveness was not determined for any NO_x control device.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: Cost impacts were not assessed for any NO_x control devices since no unit was found to be technically feasible. It should be noted that, in the 2011 PR analysis, cost impacts were assessed for the RSCR unit. These costs ranged from $17,603 per ton of controlled NO_x for Line 1, to $22,709 per ton of

[7] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

control NO_x for the SolaGen. These costs demonstrate that, even when a costing analysis is performed, the $/ton cost is extremely high for a unit of unknown performance and reliability.

ARD: The cost of replacing or controlling the ROEMMC burner should be evaluated.

Factor 2: Time Necessary for Compliance

MDEQ: No new controls were brought forward. However, the Babcock boiler and SolaGen already utilized low NO_x burners and these will continue to provide relatively low NO_x emissions as long as the units are in operation.

ARD: The time necessary for replacing or controlling the ROEMMC burner should be evaluated.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: Energy impacts were not assessed for any NO_x control devices since no unit was found to be technically feasible. However, it should be noted that the RSCR units require both fossil fuel and electricity. Fossil fuel would be used to reheat the dryer exhaust gas from approximately 140°F to 600°F or higher. Additionally, electricity is used to operate the powerful fans required to overcome the pressure drop across the catalyst bed.

Another less quantifiable impact from energy use is the impact from producing the electricity and mining the fossil fuel. Both the production of electricity and the use of fossil fuel for combustion would result in greenhouse gases and other pollutant emissions.

It should be noted, however, that RSCR units require the use of catalysts that must be disposed of. The catalysts will most likely be considered a hazardous waste. Additionally, SNCR, SCR, and RSCR units all require the use of ammonia injected into the exhaust stream and unreacted excess ammonia would be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue. Therefore, there is a trade-off between maximizing NO_x emission reductions and minimizing ammonia slip. The use of ammonia or urea also introduces certain transportation and handling risks that also can have safety and environmental concerns.

ARD: None of these impacts is unusual or unique to this facility. The impacts of replacing or controlling the ROEMMC burner should be evaluated.

Factor 4: Remaining Useful Life

MDEQ: Useful life was not assessed for any of the NO_x control devices since none were found be technically feasible.

ARD: If MDEQ is exempting the ROEMMC burner based upon age, a federally-enforceable shut-down condition should be included in the permit.

Step 5 – Select Reasonable Progress Control

MDEQ: None of the control options identified in this analysis were deemed technically feasible. The current controls include the newer sanderdust boiler installed in 2015 with a low NO_x burner, which has contributed to a decrease in the NO_x emission rate from the facility since the 2011 assessment.

Based on the analysis above, Montana concurs that the utilization of the existing controls for the sanderdust burners is adequate for Regional Haze purposes. No controls are required for the second planning period.

Conclusions & Recommendations

ARD: A full four-factor analysis of replacing or controlling the ROEMMC burner is warranted.

2.2.7 Colstrip Energy Ltd Partnership

Summary of NPS Recommendations and Requests for Colstrip Energy Ltd Partnership

Our review of the four-factor analysis for the Colstrip Energy Limited Partnership (CELP) power plant shows that there are cost-effective controls available to reduce emissions from this facility. Our estimated costs for SO_2 controls range from \$2,929 to \$4,578 per ton of SO_2 removed, and our estimated costs for NO_x controls range from \$1,303 to \$1,963 per ton of NO_x removed. Other states have set cost-effectiveness thresholds of \$5,000/ton (Texas), \$7,000/ton (New Mexico), and \$10,000/ton (Colorado and Oregon). Our cost estimates are detailed in the following discussion.

Review of Four-factor Analysis Cost Estimates

SO_2 control cost analysis

The Colstrip Energy Partnership Limited power plant consists of a single circulating fluidized bed (CFB) boiler rated at 43 MW. The boiler burns burn low-British thermal unit (Btu) waste coal.

Limestone is currently injected into the fluidized bed to remove some of the sulfur in the fuel. The four-factor analysis evaluated three possible add-on control technologies for further reducing SO_2 emissions but dismissed the potential for a circulating dry scrubber (CDS) due to high particulate loading. We do not agree that consideration of a CDS system should be eliminated. The analyses of hydrated ash reinjection (HAR), spray dry absorber (SDA), and dry sorbent injection (DSI) systems all include the cost of an upgraded baghouse; this should be done for a CDS system as well. According to Sargent & Lundy (S&L)[8], CDS can achieve SO_2 removal of 98% or greater over a large range of inlet sulfur concentrations. The lowest SO_2 emission guarantees for a CDS desulfurization system are 0.04 lb/MMBtu. Recent industry experience has shown that a CDS system has a similar installed cost to a comparable SDA. There should be a demonstration that a technology is not available, or, if it is available, that it is not applicable to a particular situation before it can be determined to be technically infeasible. The S&L Integrated Planning Model (IPM) costing method includes the cost of a new baghouse. There is no analysis included to demonstrate why the characteristics of the CDS system are incompatible with the CELP boiler.

We estimated SO_2 control costs in two ways. First, we applied the method used by Bison in Appendix B of the CELP 4-factor analysis for the three technologies identified as technologically feasible (HAR, SDA, and DSI). Bison based its calculations on the EPA Cost Control Manual, 6th edition, Section 5.2,

[8] https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-2_sda_fgd_cost_development_methodology.pdf

Chapter 1 Wet Scrubbers for Acid Gas Removal, December 1995. Our calculations are documented on separate tabs in the spreadsheet CELP_SO2_costs_6th_ed_CCM.xlsx. The cost of a baghouse was included, and costs for the baghouse are estimated in the spreadsheet CELP_baghouse_costs.xlsx.

Inputs and formulas for the SO_2 control analyses are presented in Appendix B of Bison's four-factor analysis. However, some of the factors used in the cost analyses appear to be overestimated. We calculated the costs using Bison's method with the following adjustments:

- Bison used a retrofit factor of 1.3 in evaluating potential SO_2 controls. According to EPA guidance, a retrofit factor of 1 should be used for retrofits of average difficulty. While it may be appropriate in some cases to use a value of up to 1.5, the choice of a value greater than 1 should be documented. As Bison's analysis did not provide an explanation of why 1.3 would be appropriate, we used a retrofit factor of 1.
- Bison based its costs upon the 2011 analysis and increased costs to 2019 by applying the ratio of the respective Consumer Price Indices (CPI). Instead, the Cost Control Manual recommends use of the Chemical Engineering Plant Cost Index (CEPCI). The 2011 CEPCI was 593.2 and the 2019 CEPCI was 607.5. We applied the CEPCI ratio to all 2011 costs.
- We used the current (November 2021) prime interest rate of 3.25% instead of 5.5% as used by Bison.
- As Montana does not have sales taxes, we set the sales tax cost to 0.
- Since no retirement date has been established for the CELP boiler, we used a 30-year equipment lifetime.

In addition, costs for lime should be updated using current prices, rather than estimated from 2011 costs using an inflation factor.

As the guidance used by Bison to estimate SO_2 control costs is now 25 years old, we also estimated costs using the Excel workbook provided by EPA along with the 7th edition of the Control Cost Manual, which was updated in April of 2021 (https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution). This worksheet includes cost estimates for dry scrubber systems. The estimation methods in Section 5, SO_2 and Acid Gas Controls are based upon the Integrated Planning Model; EPA has used this model in its BART analyses. Sargent and Lundy's guidance document on this model[9] notes that while the lowest available guarantee for SO_2 removal using a retrofit spray dry absorber system is 0.06 lb/MMBtu, their recommended emissions floor for a "typical" retrofit scenario is 0.08 lb/MMBtu. The total capital investment cost using EPA's guidance includes the equipment cost for the scrubber, the cost of auxiliary equipment, the cost of a baghouse, direct and indirect installation costs, costs for buildings and site preparation, the cost of land and working capital. Our calculations are documented in the spreadsheet CELP_SO2_29Nov21.xlsm. We used input factors from Bison's analysis with appropriate adjustments:

- We used a 30-year equipment life.
- We applied the current (Nov 2021) prime interest rate of 3.25% instead of 5.5% as used by Bison.

[9] Sargent and Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, January 2017

- We used a controlled SO_2 emissions rate of 0.08 lb/MMBtu, as this is recommended in Sargent and Lundy's guidance for the typical retrofit scenario. This results in a control efficiency of 84%.
- We used a retrofit factor of 1.

The resulting cost estimates are presented in the following table along with Bison's cost estimates:

Table 12. CELP SO_2 Control Cost Estimates

Cost estimation method	EPA CCM 6th Edition						EPA CCM 7th Edition
Control technology	Hydrated ash reinjection		Spray dry absorber		Dry sorbent injection		Spray dry absorber, circulating dry scrubber
Analysis performed by:	Bison	NPS	Bison	NPS	Bison	NPS	NPS
Control efficiency (%)	50	50	80	80	50	50	84
Annual emissions removed (tpy)	616	616	985	985	616	616	1036
Average annual cost effectiveness ($/ton)	$5,052	$3,585	$4,321	$3,028	$3,719	$2,929	$4,578

NO_x **control cost analysis**

The four-factor analysis considered two post combustion controls to lower NO_x emissions—selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Bison used the guidance contained in the EPA Pollution Cost Control Manual, 6th Edition, January 2002. Capital cost estimates were obtained from a 2011 report by Metso and projected to 2019 using an inflation factor based on the consumer products index. As with the SO_2 analysis, some of the cost factors in the NO_x control cost analyses appear to be overestimated. We estimated costs using Bison's method, but made the following adjustments:

- Bison based its costs upon the 2011 analysis and increased costs to 2019 by applying the ratio of the respective Consumer Price Indices (CPI). Instead, the Cost Control Manual recommends use of the Chemical Engineering Plant Cost Index (CEPCI). The 2011 CEPCI was 593.2 and the 2019 CEPCI was 607.5. We applied the CEPCI ratio to all 2011 costs.
- We applied the current (Nov 2021) prime interest rate of 3.25% instead of 5.5% as used by Bison.
- For SCR, we chose a 30-year life rather than 20 years as recommended for power plants by the EPA Control Cost Manual, Section 4, Chapter 2, section 2.4.2.
- For SCNR, we calculated the normalized stoichiometric ratio using the equation from the Control Cost Manual, $(2*NOx_{in} + 0.7)*\eta_{NOx}/ NOx_{in}$, rather than reading it from a chart. This resulted in a value of 1.875 instead of 3.
- We used a retrofit factor of 1.

Our calculations based upon the 6th edition of the Control Cost Manual are documented in the worksheet CELP_NOx_control_estimates_2002_manual.xlsx.

As the analysis method contained in the 2002 CCM is now 19 years old, we also calculated costs of NO_x controls using EPA's updated manual. We referenced the 7th edition of the CCM, including Section 4, Chapter 1 for SNCR (dated April 2019) and Chapter 2 for SCR (dated June 2019). We used worksheets EPA provided with the 7th edition of the manual to estimate NO_x control costs. The manual and worksheets are available online at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. We made the same adjustments to the retrofit factor and the interest rate as those listed in the preceding paragraph. We chose ammonia as the reagent and Method 1 to calculate the catalyst replacement cost and used the default value of 1.05 for the NSR as indicated in the spreadsheets for ammonia. The results can be found in the worksheets entitled CELP_SNCR_Nov21.xlsm and CELP_EPA_SCR_worksheet.xlsm. The results of the NO_x control cost calculations are listed in Table 2, along with the cost estimates provided by Bison in the four factor analysis.

Table 13. NOx Control Cost Estimates

Cost estimation method	EPA CCM 6th Edition 2002				EPA CCM 7th Edition 2019	
Control technology	SCR		SNCR		SCR	SNCR
Analysis performed by:	Bison	NPS	Bison	NPS	NPS	NPS
Control efficiency (%)	80	90	50	50	90	50
Annual emissions removed (tpy)	714	803	446	446	798	443
Average annual cost effectiveness ($/ton)	$3,179	$1,963	$1,527	$1,303	$2,656	$1,627

The costs estimated by NPS for SCR assumed a 90% removal efficiency for SCR. If 80% efficiency is assumed, the estimated cost is $2,208 per ton using Bison's method and $2,919 using EPA's updated 2019 worksheet.

2.2.8 Graymont Western U.S. Inc.

Summary of NPS Recommendations and Requests for Graymont Western U.S. Inc.

NPS ARD review of the four-factor analysis conducted for Graymont Western US Inc. (Graymont) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from the facility. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The annual average cost effectiveness of adding dry scrubbing at Graymont's Indian Creek plant would be acceptable in the context of the cost thresholds used by NM, CO, and OR. Dry scrubbing could reduce SO_2 emissions at this facility by over 200 tons/year.

In addition, the cost effectiveness of adding SNCR to reduce NO_x emissions would be acceptable in the context of the thresholds used by each of the states referenced above. SNCR at Graymont's Indian Creek plant could reduce annual NO_x emissions by over 184 tons/year.

We recommend that MDEQ require the technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

Graymont Western US Inc. (Graymont) operates two horizontal rotary preheater lime kilns at its Indian Creek Plant is located in Broadwater County near Townsend, Montana, approximately 135 km north of Yellowstone National Park, a Class I area administered by NPS.

MDEQ: The two kilns are nearly identical in design and operations, although constructed at different times. Kiln #1 was installed in 1982 and Kiln #2 was installed in 1990. Each kiln has a nominal lime production rate of 500 tons per day.

Both kilns can utilize coal and petroleum coke as fuels for the lime production process. Typical annual fuel usage rates for both kilns combined are approximately 40,000 tons per year of coal (at 8,600 Btu/lb) and 20,000 tons per year of coke (at 14,400 Btu/lb). Fuels typically used for kiln startup include diesel and propane. Natural gas is not available at the plant.

Graymont RepBase and 2028 OTB /OTW Scenarios

MDEQ: Graymont selected the 2017-2018 two-year average emissions as their representative baseline. MDEQ concurred that this two-year period was reflective of recent normal operation. Graymont also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Graymont chose not to scale the representative baseline emissions to the future OTB/OTW scenario. Thus, the 2028 OTB/OTW emissions are equivalent to the 2017-2018 representative baseline emissions.

Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 14. MT Draft SIP Table 6-25. Graymont RepBase and 2028 OTB/OTW Emissions

Baseline Period	**Rep. Baseline NO_x**	**Rep. Baseline SO_2**	**2028 OTB/OTW NO_x**	**2028 OTB/OTW SO_2**
2017-2018	367.8	238.4	367.8	238.4

ARD: What are the SO_2 and NO_x emission rates in lb/ton?

SO_2 Evaluation

Step 1 – Identify All Available Technologies

MDEQ: SO_2 is generated during fuel combustion in a lime kiln, as the sulfur in the fuel is oxidized by oxygen in the combustion air. Sulfur in the limestone raw material can also contribute to a kiln's SO_2 emissions, though the proportion of sulfur contained in the raw material is much less than that of the fuel.

The retrofit controls include both add-on controls that eliminate SO_2 after it is formed and switching to lower sulfur fuels which reduces the formation of SO_2. Available technologies for SO_2 were identified as: Inherent Dry Scrubbing, Alternative Low Sulfur Fuels, Wet Scrubbing, and Semi-Wet/Dry Scrubbing.

INHERENT DRY SCRUBBING

MDEQ: SO_2 is inherently scrubbed within a lime kiln system due to the presence of large volumes of alkaline materials in the system, including limestone in the preheater that all kiln exhaust gases pass through. A typical kiln system scrubs approximately 90% of SO_2 (originating from both fuel sulfur and raw material sulfur) that would otherwise leave the stack. This in-situ scrubbing mechanism is commonly determined as BACT for preheater rotary kilns being permitted today. Dry sorbent injection operates under a similar principle, using the injection of lime particulate into the process stream to initiate the same reaction. Dry sorbent injection is not considered an available control methodology, because the reaction is already taking place inherently as part of the lime kiln process.

ALTERNATIVE LOW SULFUR FUELS

MDEQ: Fuels that can be considered for use in the lime kilns must have sufficient heat content and be dependable and readily available locally in significant quantities so as not to disrupt continuous production. Also, they must not adversely affect product quality. Currently, the Graymont Indian Creek kilns utilize coal and petroleum coke during normal operations. Alternative lower-sulfur fuels that can be considered include natural gas and diesel, as well as an operating scenario using exclusively coal.

Currently, there is no natural gas supplied to the facility. The nearest natural gas pipeline is on the east side of Helena, Montana, approximately 30 miles from the plant, and there are no plans to run a pipeline towards the area of the plant. Therefore, natural gas is not considered an available alternative control method at this time.

There are no examples of kilns that fire 100% diesel fuel for lime production. Therefore, the use of diesel fuel is not a commercially established emission reduction method and is not considered an available, feasible option at this time.

The all-coal scenario will be considered going forward.

ARD: What are the sulfur contents of the coal and pet coke currently burned?

WET SCRUBBING

MDEQ: A wet scrubber is an add-on technology that may be installed downstream of the kilns.

Step 2 – Eliminate Technically Infeasible Options

MDEQ: Inherent dry scrubbing occurs in the lime kiln systems and is particularly effective in rotary preheater type kilns. Baseline emissions account for this form of SO_2 control. All alternative methods of SO_2 control in this analysis conservatively assume that the kilns maintain the current level of inherent dry scrubbing.

ALTERNATIVE LOW SULFUR FUELS

MDEQ: The use of entirely coal as the primary source of fuel is technically feasible and will be considered further.

WET SCRUBBING

MDEQ: A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO_2 from stack gas. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge. Graymont estimates that the slurry required per kiln will be approximately 250 gallons per minute (gpm) of water. Approximately 50% of this water can be recovered from dewatering efforts. The remaining 125 gpm per kiln will need to be continuously added to the system. For both kilns, this amounts to 131.4 million gallons per year.

The Indian Creek plant's water rights entitle the plant to use up to 75 million gallons per year. Plant records indicate the facility's current water usage is approximately 5 million gallons per year. Therefore, at most only 70 million gallons are available to the plant for additional needs. Because the facility would need over 131 million gallons per year to operate the wet scrubbers, the facility would need to acquire the rights to more than an additional 61 million gallons of water per year to operate two wet scrubbers and provide for possible other demands by the plant for water. All water rights in that area of Montana have already been appropriated, so the facility does not have the water resources available to operate wet scrubbers at the facility.

Wet scrubbing SO_2 control technology is technically infeasible for this facility because the Indian Creek plant does not have adequate water resources to operate wet scrubbers. Therefore, this technology is not considered further.

ARD: We agree.

SEMI-WET/DRY SCRUBBING

MDEQ: Semi-wet/dry scrubbing uses considerably less water than wet scrubbing; therefore, it is technically feasible and will be considered further.

ARD: We agree.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: The remaining technologies are estimated as having the following SO_2 control efficiencies.

Semi-wet/dry Scrubbing	90.0%

Alternative Low Sulfur Fuel – All Coal	51.8%
Inherent Dry Scrubbing	Base case

The following assumptions have been applied to each of the estimates noted above.

- Assumes 95% control equipment uptime.
- The alternative fuel scenario reduction efficiency is calculated using a material balance on the fuel sulfur, with fuel sulfur emissions reductions assumed to be independent of feed sulfur emissions and inherent dry scrubbing.
- Estimated inherent SO_2 control efficiency is 90%. Additional reductions from alternative control methods are applied to the base case, conservatively assuming that reduction from inherent dry scrubbing is unaffected by the reduction options.

The alternative fuel scenarios have a calculated control efficiency that considers two key assumptions:

- Changing the primary fuel will fully reduce sulfur by the difference in sulfur levels between the fuel types being compared, affecting only the emissions directly resulting from sulfur contained in the fuel. SO_2 emitted from sulfur contained in the raw material that is processed in the kilns is assumed to not be affected.
- The control efficiencies assume the same level of in-situ scrubbing reduction takes place under all fuel scenarios. These alternative fuel efficiency values are the incremental control efficiencies that take place as a result of the fuel switching beyond the inherent control.

Given the complexity of the inherent scrubbing's impact on SO_2 resulting from fuel sulfur vs. raw material sulfur, assuming the fuel switching fully reduces sulfur by the difference in sulfur levels between the fuel types is particularly conservative. In reality, inherent SO_2 reduction would likely be substantially reduced when the SO_2 concentration in the exhaust stream routed through the pre-heater is reduced.

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of semi-wet/dry scrubbing have been estimated by scaling the capital and operating costs used in the first planning period by the Chemical Engineering Plant Cost Index (CEPCI). The alternative all-coal fuel scenario calculations are determined using the fuel costs associated with plant operations during baseline emission years. Currently, the Indian Creek kilns utilize a combination of approximately 70% coal and 30% coke by mass.

ARD: Please provide these calculations.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: The capital and operating costs of the semi-wet/dry scrubber used in the cost effectiveness calculations are estimated based on vendor quotes obtained during the first planning period for similar sources, along with published calculations methods. The capital cost is annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized cost.

The cost of the fuel switching used in the cost effectiveness calculations is determined by calculating the current annual cost of using a coal and coke blend and determining the increased cost of switching to all coal, all diesel, and all natural gas.

The Graymont Indian Creek plant currently uses a low heat content coal (Powder River Basin [PRB]) that is obtained locally. To bring the kiln system to the required calcination temperature range, Graymont must blend this coal with a higher heat content fuel such as petroleum coke. In considering the all-coal alternative fuel scenario, it would not be technically feasible to use all PRB coal for the analysis. Therefore, Graymont factored in the composition and cost of an appropriate quality coal that would need to be transported to the plant and blended with the PRB coal.

Switching fuel may require changes to the burners and the fuel storage, processing, and delivery system. These factors are significant, especially for the all-natural gas alternative fuel scenario. For this case, there would be a significant capital cost to establish a line from the nearest pipeline, which is approximately 30 miles from the plant. For this analysis, however, capital expenses are not included.

The cost effectiveness for the two alternatives is shown below.

Table 15. MT Draft SIP Table 6-26. Graymont SO_2 Cost Effectiveness

Control Option	**Control Cost ($/yr)**	**Baseline Emission Level (tons)**	**SO_2 Reduction (%)**	**Emission Reduction (tons)**	**Cost Effectiveness ($/ton removed)**
Semi-wet/dry Scrubbing	$3,939,630	238.39	90.0%	203.82	$9,664
Alt. Fuel – All Coal	$1,887,649	238.39	51.8%	123.45b	$15,290

ARD: We identified several errors in the Graymont analysis:

The current CCM method apples a Contingency based upon 5% - 15% of the Direct+Indirect Costs—we used 10%.[10] Graymont applied a 3% Contingency Factor to the Purchased Equipment Cost and thus underestimated the contingency cost.

Graymont assumed 3,840 man-hours for Operating Labor. The CCM recommends 0.5 hr/shift. As a result, Graymont has overestimated labor, maintenance, and administrative costs.

Graymont included property taxes which are not assessed on air pollution control equipment in MT.

Graymont assumed amortization over a 20-year equipment life at 5.5% interest. The CCM recommends a 30-year scrubber life and use of the current (3.25% as of November 2021) interest rate.

[10] The default value for the contingency factor, CF, is 0.10. However, values of between 0.05 and 0.15 may be included to account for unexpected costs associated with the fabrication and installation of the control system. More information can be found on contingency in the cost estimation chapter of this Manual.

We adjusted Graymont's costs to 2019$ using the CEPCI and estimate a cost-effectiveness of $5,167/ton.

Factor 2: Time Necessary for Compliance

MDEQ: Graymont has indicated that any controls which are identified as part of the analysis, could be implemented by 2028 but believes the base case of inherent scrubbing is providing reasonable SO_2 control.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: The cost of energy required to operate the control devices has been included in the cost analyses. To operate any of the add-on control devices, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations.

Most of the alternative SO_2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them. A semi-wet/dry hydrated lime control system, for example, will require water to hydrate lime. There will also be additional material collected in the baghouses that will require disposal concerns for water scarcity is a significant concern. This is especially true when weighing the benefits of a wet vs. a semi-wet or dry control technology, as wet scrubbing requires a significant quantity of water. In addition, environmental concerns associated with sludge disposal and visible plumes are distinct possibilities.

ARD: The only unusual impact is the issue of the availability of water. This eliminates the use of a wet scrubber and favors the dry-scrubbing technologies.

Factor 4: Remaining Useful Life

MDEQ: The remaining useful life of the kilns is expected to be at least 20 years.

ARD: In the absence of a federally-enforceable shut-down condition, we assumed a 30-year scrubber life.

Step 5 – Select Reasonable Progress Control/Final State Recommendations:

MDEQ: The lime production process inherently removes the majority of SO_2 that is created from the process. This inherent control measure was BACT for these kilns when they were originally constructed. Inherent scrubbing can still be an effective control mechanism to remove the majority of SO_2. MDEQ determined that no additional SO_2 control is required for the second planning period.

ARD: The BACT determination out-of-date.

NO_x Evaluation

Step 1 – Identify All Available Technologies

MDEQ: NO_x is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. Thermal NO_x emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_x emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Most of the NO_x formed within a rotary lime kiln is classified as thermal NO_x. Virtually all the thermal NO_x is formed in the region of the flame at the highest temperatures, approximately 3,000 to 3,600 °F. A small portion of NO_x is formed from nitrogen in the fuel that is liberated and reacts with the oxygen in the combustion air. The following NO_x control technologies were identified for the Graymont kilns; those using combustion controls and those using post-combustion control.

Reduce Peak Flame Zone Temperature
Low NO_x Burners
Kiln Operation Preheater Kiln Design
Selective Catalytic Reduction
Selective Non-Catalytic Reduction

REDUCE PEAK FLAME ZONE TEMPERATURE

MDEQ: These are methods of reducing the temperature of combustion products in order to inhibit the formation of thermal NOx. They include (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit amount of energy input; (3) injecting cooled, oxygen depleted flue gas into the combustion air; and (4) injecting water or steam.

LOW NOX BURNERS

Graymont: LNBs reduce the amount of NO_X initially formed in the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). LNBs are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The longer, less intense flames reduce thermal NO_x formation by lowering flame temperatures. Control of air turbulence and speed is often controlled via mixing air fans. Some of the burner designs produce a low pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low pressure zone tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen, thus producing the effect of flue gas recirculation. Reducing the oxygen content of the primary air creates a fuel-rich combustion zone that then generates a reducing atmosphere for combustion. Due to fuel-rich conditions and lack of available oxygen, formation of thermal NO_x and fuel NO_x are minimized.

PREHEATER KILN DESIGN/ PROPER COMBUSTION PRACTICES

MDEQ: The use of staged combustion and preheating alone can lead to effective reduction of NO_x emissions. By allowing for initial combustion in a fuel-rich, oxygen-depleted zone, necessary temperatures can be achieved without concern for the oxidation of nitrogen. This initial combustion is then followed by a secondary combustion zone that burns at a lower temperature, allowing for the addition of additional combustion air without significant formation of NOx.

SELECTIVE CATALYTIC REDUCTION

MDEQ: As of this report, there are no known instances of SCRs installed on lime kilns.

Selective Non-Catalytic Reduction

MDEQ: In cement kilns SNCR can be applied as a post combustion technology or in a certain combustion zone of kilns to facilitate SNCR (mid-kiln SNCR). The lime industry has a severely limited track record in determining the feasibility or control level that could be attained if mid-kiln SNCR were attempted on the Indian Creek kilns. The aforementioned technical barriers to SNCR implementation have limited the technology's use in the industry, with temperature, residence time, and lower NO_x concentrations distinguishing lime production from the cement production process. A search of the RBLC database indicates that there is only one instance of a lime kiln that was permitted with SNCR as control for NO_x emissions. The permit documents indicate that after conducting a trial with the SNCR, a lower limit would be established that considers the control of NO_x emissions achieved by the SNCR. Updated permit files have not included a reduced permit limit, and there is no publicly available evidence of the trial results. Based on the record, the SNCR installation and reduction for this RBLC search result has not been demonstrated. Additionally, for the one instance of known SNCR installation on a different lime kiln (which does not appear in RBLC results), very limited information is available on the details of this kiln necessary for Graymont to evaluate whether the application of SNCR in that instance could be implemented at Indian Creek. Therefore, there is not enough information to conclude that SNCR has been demonstrated as a successful control option for NO_x emissions from lime kilns.

ARD: SNCR has been successfully applied to a lime kiln at the Lhoist North America plant in Nelson, AZ, to comply with a BART FIP, as well as at two lime kilns in AL (see attachment).

Step 2 – Eliminate Technically Infeasible Options

Reduce Peak Flame Zone Temperature

MDEQ: In a lime kiln, product quality is co-dependent on temperature and atmospheric conditions within the system. Although low temperatures inhibit NO_x formation, they also can inhibit the calcination of limestone. For this reason, methods to reduce the peak flame zone temperature in a lime kiln burner are considered concern for lime quality and therefore are eliminated.

Low NO_x Burners

MDEQ: The facility currently operates Pillard low NO_x burners in the lime kilns. Coal and coke are delivered to the burners using a direct fired system. However, to limit NOx, only enough primary air is used to sweep coal and coke out of the mill. This is similar to using an indirect fired system, which also limits primary air to the burners while delivering fuels. Baseline emissions are based on the operation of these low NO_x burners. All alternative methods of NO_x control in this analysis will assume that the kilns continue to operate these burners.

Preheater Kiln Design/Proper Combustion Practices

MDEQ: Proper combustion practices and preheater kiln design are considered technically feasible for Graymont and will be considered further.

Selective Catalytic Reduction (SCR)

MDEQ: Efficient operation of the SCR process requires fairly constant exhaust temperatures. Fluctuations in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. If the temperature is too high, oxidation of the NH_3 to NO can occur. Also, to achieve higher removal efficiencies, some excess of NH_3 is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (as ammonia salts result from the reduction of NO_x and are emitted in a detached plume) and increased SO_3 emissions (from oxidation of SO_2 on the catalyst).

To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 350°F), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 480°F to 800°F. The source of heat for the heat exchanger would be the combustion of fuel, with combustion products that would enter the process gas stream and generate additional NOx. Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional NO_x control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and semi-dust SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses.

A semi-dust system is similar to a high dust system. However, the SCR is placed downstream of an ESP or cyclone. The main concern with high dust or semi-dust SCR is the potential for dust buildup on the catalyst, which can be influenced by site specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup could reduce the effectiveness of the SCR technology, and make cleaning of the catalyst difficult, resulting in kiln downtime and significant costs.

No lime kiln in the United States is using any of these SCR technologies. For the technical issues noted above, post combustion, high dust and semi-dust SCR's are considered technically infeasible at this time.

SELECTIVE NON-CATALYTIC REDUCTION

Graymont: Based on the temperature profile, there are three locations in a rotary preheater lime kiln system where the ammonia /urea injection could theoretically occur: the stone/preheater chamber, the transfer chute, or after the PMCD. A fourth location that will be considered in this analysis is the kiln tube. In order for SNCR to be technically feasible, at least one of these locations must meet the following criteria: placement of injector to ensure adequate mixing of the ammonia or urea with the combustion gases, residence time of the ammonia with the combustion gases, and temperature profile for ammonia injection. (Figures 5 and 6 represents a typical lime kiln preheater, and are not specific to the kilns at the Graymont Indian Creek facility.)

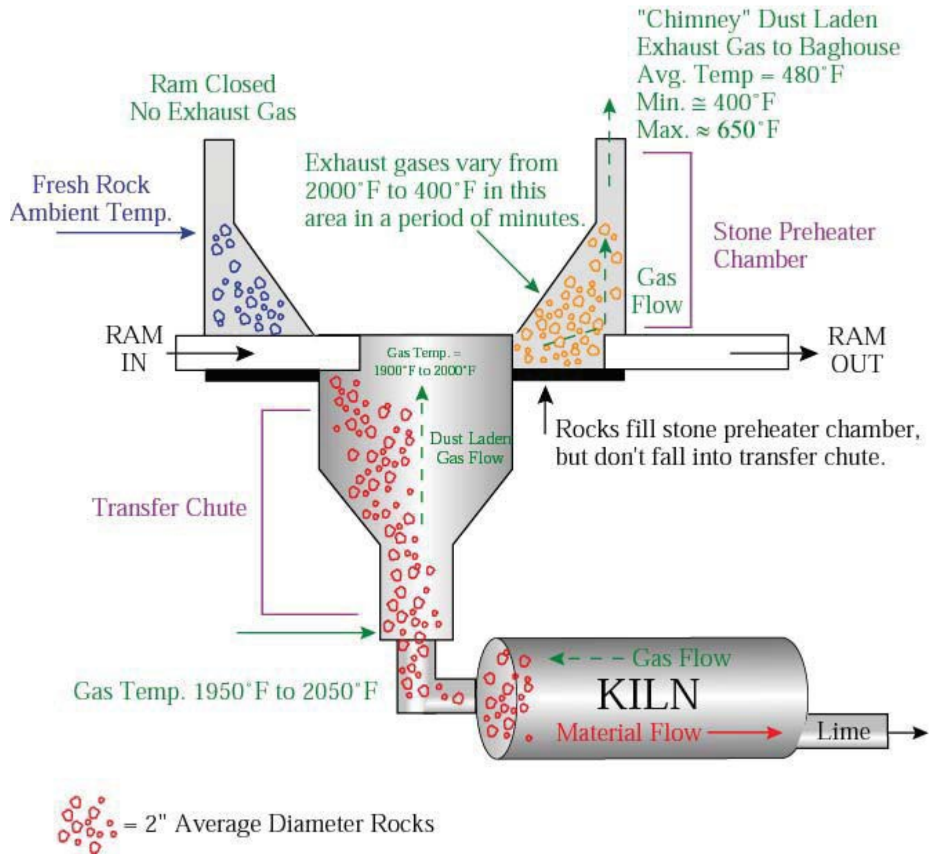

Figure 5. Preheater Cross Section

- SNCR Ammonia/Urea Injection Location - Stone Chamber/Preheater

Graymont: The required temperature range for the reaction may occur within the preheater. However, the location of the temperature zone varies with time and location as explained below.

In each Graymont Indian Creek preheater, mechanical rams operate in sequence, transferring limestone, one ram at a time, from the stone chambers into the transfer chute. When a ram is in the "in" position, very little exhaust gas flows through the stone and out the duct. When the ram pulls out, the cold stone drops down and fills the stone heating chamber. The angle of repose of the stone and the configuration of the duct and chamber are such that stone does not continue to fall into the transfer chute. Hot gases, at approximately 1,950°F, then pass through the stone chamber filled with cold stone. The first gas to pass through the chamber exits the chimney at approximately 400°F. As the cold stone heats up, the exit gas temperature increases and reaches a high of approximately 600°F. The ram then strokes and pushes the heated stone into the transfer chute and starts the cycle again. The temperature profile in the stone chamber varies as shown in the figure below.

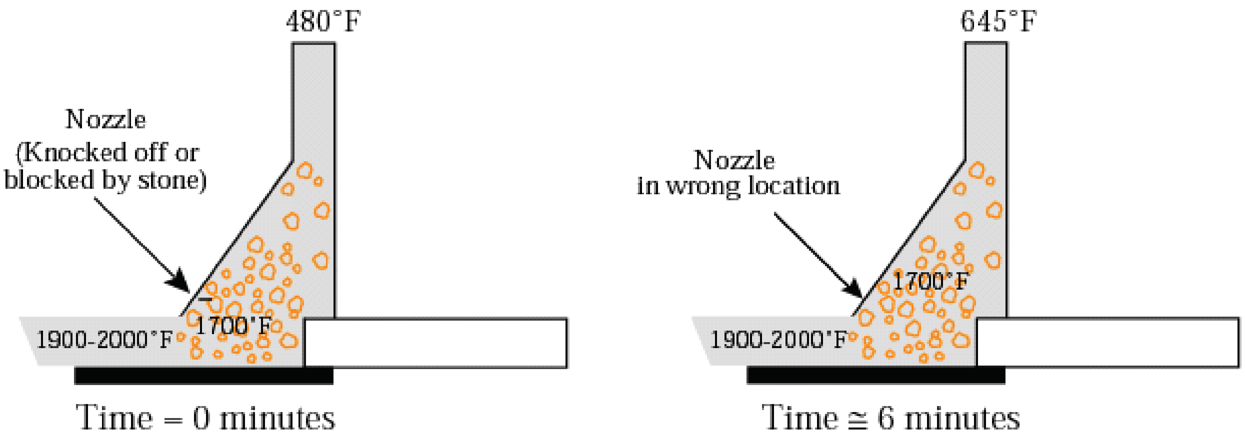

Figure 6. Preheater Stone Chamber Temperature Variation with Time and Location

*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Indian Creek facility

Besides the fact that the optimal temperature zone varies in location, the fact that the stone chamber is filled with stone makes using nozzles for injecting the ammonia/urea infeasible. For example, if a nozzle protruded from the wall of the stone chamber, the moving packed bed of rock would either knock it off or wear it off in a very short time. If the nozzle were inset into the wall of the chamber, the moving packed bed of stone would block the spray, and the ammonia or the urea mixture would simply coat a few of the stones, rather than mixing evenly throughout the gas stream. Similarly, if the nozzle were positioned at the roof of the preheater, the ammonia or urea would not be distributed throughout the gas stream. The preheater is approximately 75 percent full of stone, so ammonia or urea sprayed from the top of the preheater would have minimal residence time for distribution through the combustion gases before it would be blocked from distribution by the stone. Regardless of the choice of location for the nozzle, the ammonia or urea would not be effectively distributed through the large surface area of the preheater. These problems make application of SNCR in the stone chamber technically infeasible.

- SNCR Ammonia/Urea Injection Location – Transfer Chute

MDEQ: The temperature in the transfer chute is approximately 1,950°F for typical kilns. These temperatures are in the upper range for the NO_x reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NO_x reduction in low dust exhaust streams. Lime kilns do not have clean exhaust streams at this location. Rather, the back end of the transfer chute is an extremely dusty environment, and therefore the exhaust stream is dust-laden. The one SNCR installation in the lime industry has achieved control efficiencies of around 50% with the injection nozzles installed in the bottom of the preheater, at the preheater cone. While this technology is certainly promising, this one example of SNCR installation on a rotary lime kiln does not necessarily transfer to other lime kilns.

Effectiveness of SNCR is highly site-dependent, with a variety of factors having the potential to heavily influence the quantities of NO_x controlled. Until such time as more information is available that demonstrate successful operation of SNCR systems on rotary lime kilns, this location is also infeasible.

- SNCR Ammonia/Urea Injection Location - Inside Rotary Kiln

Ammonia/urea could be injected through a door or port in the kiln shell. Similar to the transfer chute, stone is traveling down the rotary kiln. Consequently, the nozzle would need to be positioned out of the direct path of the flow of the stones. Theoretically, the temperature inside a rotary lime kiln, which is above 2,200 F, would promote the formation of NO from injected ammonia.

Graymont stated that they were aware that there have been trials at competing lime facilities with mid-kiln ammonia injection and transfer chute ammonia/urea injection for NO_x reduction. However, the technology costs and technical details have not become publicly available, so evaluating this further is considered infeasible at this time.

ARD: In preparing its Federal Implementation Plan (FIP) for the Nelson facility, EPA R9 relied upon a report that estimated that the Nelson kilns, which are very similar to Indian Creek kilns 1 and 2, could achieve 50% NO_x reductions with SNCR.[11] We understand that the Nelson kilns are meeting the FIP limits and we are using the same 50% reduction estimate in our analysis. Furthermore, Lhoist North America submitted comments (attached) to Illinois EPA that support the 50% control assumption at a competitor's lime kiln proposed in that state.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: Graymont determined in their four-factor analysis that low NO_x burners were feasible. Graymont identified that they currently are using low NO_x burners. Graymont also stated they believe SCR and SNCR are not commercially available, although Graymont did provide a cost estimate for SNCR to demonstrate the magnitude of what those costs might be. Montana has not included that analysis within this section. Future additional technology advancements and further system demonstrations of successful SNCR operations may require further evaluations for the Graymont kilns.

ARD: We prepared our own evaluation based on the information provided.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: As indicated above, the Graymont four-factor analysis indicates that all options except low NO_x burner technology have been eliminated. However, Graymont did bring forward an SNCR cost estimate.

Graymont: In order to assess the cost of compliance for the installation of SNCR, the EPA Control Cost Manual is used. Capital costs for the installation of the SNCR assumed a 20-year life span for depreciation, as well as the current bank prime rate of 5.5% for interest calculations, per MDEQ and EPA guidance. The total capital investment includes the capital cost for the SNCR itself, the cost of the air pre-heater required (per the EPA Control Cost Manual, the air pre-heater will require modifications for coal-fired units when SO_2 control is necessary. This value is conservatively assumed for all coal-fired units evaluated for SNCR installation, and the balance of the plant. Annual costs include both direct costs such as maintenance, reagent, electricity, water, fuel, and waste disposal cost and indirect costs for administrative charges and the annuitized capital costs as a capital recovery value. A retrofit factor of 1.5 is used to account for the technical barriers described in section 6.2.2.1, including only one known SNCR retrofit on a lime kiln, the difficulty of identifying an injection point that allows for ammonia to enter the

[11] D-02 2012-10-03 - UNC Task 7 Deliverable (CLC Nelson-SundT4-Catalyst Paper BART Analysis Report) _final

gas stream within an optimal temperature window, the low residence times of lime kilns relative to cement kilns, and the relatively low inlet NO_x concentrations that limit the effectiveness of the control technology. The total costs and cost effectiveness of control are summarized below.

Table 16. Total Costs and Cost-Effectiveness of Control

Total Capital Investment	Total Annual Cost	NO_x Emissions Removed (tpy)	Cost Effectiveness ($/ton removed)
$8,603,378	$879,163	66	$13,303

MDEQ: That number indicates a cost effectiveness of approximately $13,000 per ton of NO_x removed. Even if the technology further develops, and at double the NO_x removal rate which was estimated, the cost effectiveness would still be considered moderate. See the Graymont four-factor analysis for further details.

ARD: Graymont provided a pdf copy the cost estimate spreadsheet from an out-dated version of EPA's CCM section on SNCR. From that, we were able to deduce that Graymont has overestimated SNCR costs:

Graymont included a cost for modifying the air preheater and included this footnote: "* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide." This cost not apply to lime kilns. The CCM states: "An air pre-heater modification is necessary for the control of SO3 for boilers that burn bituminous coal where the SO2 content of the coal is **3 lb**/MMBtu or greater." We have deleted the air preheater modification cost.

Graymont applied a Capital Recovery Factor (CRF) of 0.0837; this represents a 20-year equipment life amortized at 5.5% interest. Instead, the CCM recommends use of the current prime (3.25% as of November 2021) interest rate; we applied the current prime rate.

Graymont assumed 20% control by SNCR; we assumed the same 50% control that EPA used in its FIP for the similar lime kilns at the Nelson plant in AZ. We adjusted operating costs upward to account for the additional NO_x removed.

We adjusted all costs upward (based on the CEPCI) to 2019$.

We applied a 1.5 retrofit factor for the reasons Graymont presented. Our results are shown below:

Table 17. NPS ARD Revised Cost Estimates for Graymont NO_x emission controls

SNCR	Control Cost ($/yr)	Baseline Emission Level (tons)	NO_x Reduction (%)	Emission Reduction (tons)	Cost Effectiveness ($/ton removed)
Kiln 1	$365,869	172	50%	86	$4,252
Kiln 2	$379,337	196	50%	98	$3,877

Factor 2: Time Necessary for Compliance

MDEQ: If controls were determined to be necessary, Graymont believes they could be installed by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: Graymont brought forward a number of other impacts including additional energy usage and concerns for ammonia slip.

Graymont: As previously stated, the cost of energy and water required for successful operation of the SNCR are included in the calculations, which can be found in detail in Appendix C. The installation is expected to decrease the efficiency of the overall facility, particularly as significant energy and water use is needed beyond current plan operation requirements.

Factor 4: Remaining Useful Life

MDEQ: The Graymont kilns are believed to have at least 20 years of remaining useful life.

Step 5 – Select Reasonable Progress Control/Final State Recommendations:

MDEQ: Montana concurs with the Graymont prepared and submitted four-factor analysis that the technologies evaluated for NO_x reductions are not adequately demonstrated for rotary lime kilns for SCR and SNCR, and that low NO_x burners (currently in operation) are reasonable controls for this planning period. No additional NO_x control is required by MDEQ for the second planning period.

ARD: SNCR has been successfully demonstrated on similar kilns.

Conclusions & Recommendations

- We are seeing cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The annual average cost effectiveness of adding dry scrubbing at Indian Creek would be acceptable in the context of the thresholds used by NM, CO, and OR and reduce SO_2 emissions by over 200 tons/year.
- The annual average cost effectiveness of adding SNCR at Indian Creek would be acceptable in the context of the thresholds used by TX, NM, CO, and OR and reduce NO_x emissions by 184 ton/yr.
- Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.9 Montana Sulfur & Chemical Co.

Summary of NPS Recommendations and Requests for Montana Sulfur & Chemical Co.

NPS ARD agrees with MDEQ that NO_x emissions from the Montana Sulfur and Chemical Co (MSCC) are quite low and do not warrant four-factor evaluation. Our review also finds that there are technically feasible and cost-effective opportunities available to further control SO_2 emissions from the facility. The cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

Our revised analysis finds that the annual average cost effectiveness of adding SCOT SO_2 emission controls at MSCC would be cost effective in the context of the thresholds used by CO and OR. This technology could reduce annual emissions from MSCC by about 950 tons/year. In contrast, the annual average cost effectiveness of adding CBA to reduce SO_2 emissions at MSCC would exceed the cost thresholds for emission controls set by other states in this round of regional haze SIP development.

We recommend that MDEQ require technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

Montana Sulfur and Chemical Co (MSCC) is located in Billings, Montana, about 190 km northeast of Yellowstone National Park, administered by the NPS.

MDEQ: MSCC operates in conjunction with ExxonMobil Fuels & Lubricants Co - ExxonMobil Billings Refinery to process sulfur containing gases. Because the ExxonMobil Billings Refinery does not have a sulfur recovery unit within the refinery, refinery gases high in hydrogen sulfide (H_2S) are piped to MSCC. MSCC extracts sulfur from the sour refinery fuel gas (RFG) and returns sweetened fuel gas to the ExxonMobil Billings Refinery.

The MDEQ analysis is limited to emissions from the Claus/SuperClaus unit(s) and main stack at the facility since these units are responsible for 99+% of the total sulfur dioxide emissions from the plant. A NO_x four-factor analysis was not requested since the MSCC NO_x emissions are extremely low.

ARD: We agree.

MDEQ: The existing SRU unit at MSCC controls SO_2 emissions via two steps. The first is a 3-stage Claus process. (On occasion, the unit is operated in a 2-stage fashion, allowing for necessary maintenance). This process converts hydrogen sulfide (H_2S) and SO_2 into elemental sulfur (S) via the 'Claus' reaction. The general reaction is:

$H_2S + SO_2 \leftrightarrow S + H_2O$ (unbalanced).

To achieve additional reduction, the Claus process is followed up by the addition of the "SuperClaus®" technology. This technology uses selective oxidation catalysts to oxidize residual H_2S to elemental sulfur using air. The first SuperClaus unit was installed in 1998. A second (parallel) SuperClaus unit was installed in 2007/2008 as a redundant system to improve system reliability and continue reducing emissions during periods of maintenance on one of the units. Generally, the units collectively control SO_2 emissions by about 97-98% of input sulfur gases. The efficiency was recorded at 98.4% for the baseline period (2017-2018).

MSCC RepBase and 2028 OTB/OTW Scenarios

MDEQ: MSCC selected the 2017-2018 two-year average emissions as representative of a baseline emissions and Montana concurred this two-year period was reflective of recent normal operation. MSCC also selected a future year 2028 8OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls. MSCC chose to use the 2017-2018 representative baseline for the 2028 OTB/OTW scenario. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 18. MT Draft SIP Table 6-27. MSCC RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	5.8	1013.5	5.8	1013.5

ARD: What are the 2019 and 2020 emissions?

SO_2 Evaluation

Step 1 – Identify All Available Technologies

MDEQ: The most common control measures that may be applied to a typical Claus facility are generally categorized as Tail-Gas Scrubbing Treatment units (TGST). These units use either an oxidation or a reduction measure to continue to convert some of the underlying sulfur gases exiting the Claus systems to additional elemental sulfur. Another common measure of removing sulfur dioxide from some gas streams is a traditional FGD unit which is more typically used at coal or oil-fired electrical generating units. However, this is not generally applied to Claus systems in the US.

OXIDATION – REDUCTION TECHNIQUES

MDEQ: The TGST control typically adds an additional scrubbing process to the Claus exhaust stream prior to the tail-gas incinerator. The processes classically convert the Claus exhaust to either H_2S (reducing process) or SO_2 (oxidizing process). In most cases, the 'newly created' H_2S or SO_2 is then captured, concentrated and returned to the Claus portion of the facility to extend the elemental sulfur recovery. Alternatively, an oxidizing process selectively converts low-concentration hydrogen sulfide residue from the Claus system directly to elemental sulfur (e.g. SuperClaus).

There are several processes that either achieve oxidations or reductions. Regarding the oxidation method, the exhaust stream from the Claus or SuperClaus® would be treated to oxidize the various residual reduced sulfur compounds to sulfur dioxide (similar to the plant's incinerators). The sulfur dioxide is then captured, concentrated and recycled back to the Claus process itself. There are several varieties of processes within the oxidation method. They include the Stauffer, Wellman- Lord, and Aquaclaus. Only the Wellman-Lord process has been applied successfully in any US refinery.

The reduction process is the more typical refinery-based method of additional sulfur dioxide control. This process catalytically converts the sulfur-containing gases from the Claus back to H_2S. The H_2S-containing gas is then sent to a scrubber for capture prior to routing the remaining gases to a tail-gas incinerator. The H_2S scrubber typically uses a specialized amine process to selectively capture the H_2S

while rejecting carbon dioxide. Then this captured H_2S is regenerated from the specialized amine to produce a suitably concentrated stream and is then sent back to the Claus plant for reprocessing.

Five common systems utilizing the reduction-oxidation control method are the LO- CAT®, Beavon (MDEA), Shell Claus Off Treatment (SCOT), and ARCO. (Additional oxidation-reduction processes for converting H_2S into sulfur include Cold Bed Adsorption (sub dewpoint), Sulferox, Stretford, and Paques biological process.) For the oxidation-reduction processes, LO-CAT®, SCOT and CBA have been among the predominant industry choices. LO-CAT® is a proprietary liquid redox process that converts H_2S in the acid gas to solid elemental sulfur using an aqueous solution of iron as catalyst. LO-CAT® units are in service treating refinery fuel gas, off gas, sour-water- stripper gas, amine acid gas, and Claus tail gas. The SCOT process, however, is the most common in the U.S, and is discussed below.

ARD: MDEQ has not justified its exclusion of the other technologies noted above.

Shell Claus Off Treatment (SCOT)

MDEQ: In the Shell Claus Off Treatment (SCOT) process, and numerous variants, tail gas from the SRU is re-heated and mixed with a hydrogen-rich reducing gas stream. Heated oxygen-free tail gas is treated in a catalytic reactor where free sulfur, sulfur dioxide, and reduced sulfur compounds are substantially reconverted to H_2S. The H_2S-rich gas stream is then routed to a cooling/quench system where the gases are cooled, and substantial process water is condensed as sour water. Excess condensed sour water from the quench system is routed to a separate sour water system for further treatment and disposal. The cooled quench system gas effluent is then fed to an absorber section where the acidic gases (H_2S, CO_2), which must be substantially free of SO_2 to prevent damage, comes in contact with a selective amine solution and is absorbed into solution; the amine must selectively reject carbon dioxide gas to avoid problems in the following steps, and must not be exposed to unreduced materials (e.g., unconverted SO_2 or sulfur) or to oxygen that may arise during malfunctions. The rich solution is separately regenerated using steam, cooled. The regenerated amine is cooled and returned to the scrubber/absorber. The cooled H_2S-rich gas released at the regenerator is reprocessed by the SRU.

Cold Bed Adsorption (CBA)

MDEQ: The Cold Bed Adsorption (CBA) process is effectively an extension of the Claus process. The Claus reaction is driven closer to completion by a reduction in temperature over certain catalyst beds/reactors. CBA, of which Sulfreen® is one variant, operates at lower temperatures (260 to 300ºF) to recover tail-gas SO_2 and H_2S as sulfur. Claus plant and very high-quality feeds. AP-42 Chapter 8.13-Sulfur Recovery suggests the upper range is about 99% overall recovery when associated with a modern Claus design and very high-quality stable feeds.

The recovery percentage ranges represent the amount of sulfur removed from the untreated gas stream(s) entering a sulfur recovery facility and not the amount of SO_2 reduction from the existing tail gas stream. The effective reduction to the existing already controlled SO_2 emissions at MSCC would be substantially lower than the theoretically possible overall sulfur recovery rates.

LO-CAT®

MDEQ: The LO-CAT® technology uses a redox process to oxidize H_2S to elemental sulfur. It does so by using an iron based aqueous solution in which the iron acts as a catalyst. An acid gas stream is compressed and fed to an absorber unit where it contacts the dilute, iron chelate catalyst solution and the H_2S is absorbed and then directly oxidized to solid sulfur. Gas leaves the absorber for disposal via a tail gas disposal system. The reduced catalyst solution returns to the oxidizer, where sparged air reoxidizes the catalyst solution. Product water resulting from the reaction must also be removed and treated. The catalyst solution is then returned to the absorber. The presence of SO_2 or other non-H_2S species in the treated gases may make this process impractical. Sulfur is concentrated in the bottom of the oxidizer and sent to a sulfur filter, which produces the solid sulfur filter cake.

A critical concern with this technology for MSCC is the quality of the produced sulfur. Contaminants commonly present in the raw acid gas are not converted to sulfur, may remain with the product sulfur, and may be highly odorous. The catalyst itself also is a source of product contamination. MSCC not only removes sulfur from various streams at the facility, MSCC creates many saleable products. Many of the products require up to 99.9% purity to meet client demands. The LO-CAT® system does not consistently meet this expectation. Therefore, this technology is rejected because it could undermine the fundamental purpose of the facility itself.

ARD: This is the same emission control process proposed by Meridian Energy for the Davis Refinery near Theodore Roosevelt National Park. MDEQ should provide current, specific information supporting its conclusion that this technology would be unsuitable.

MDEQ: After consideration, it was decided to use the SCOT and CBA (Sulfreen®) processes as a reasonable approximation for any and all the oxidation or reduction options discussed above, for economic analysis. MSCC has, in the past, received some cost estimates information from some designers as well as other information helpful to the process. In addition, the removal efficiency potentials for these two processes are relatively similar. Should either the SCOT or CBA technologies (as a representative of oxidation or reduction option) indicate a low dollar/ton cost effectiveness, then a more detailed review may be appropriate. That review could or would extend to other processes previously mentioned.

ARD: We would like to see a more-thorough discussion of the LO-CAT® system.

Flue Gas Desulfurization Techniques

MDEQ: The second class of sulfur dioxide scrubbing for consideration is the Flue Gas Desulfurization (FGD) unit. As noted earlier, this is the typical sulfur dioxide control system found in most coal and oil-fired electrical generation systems across the U.S. The FGD unit may be configured as a wet, semi-dry, or dry scrubber system. In all cases an alkaline compound (typically $CaCO_3$ or CaO) is used to react with SO_2 (an acidic gas) to form a compound such as CaSO3. The $CaSO_3$ (and its related compounds) are then removed via a particulate control device such as a baghouse.

Step 2 – Eliminate Technically Infeasible Options

Flue Gas Desulfurization (FGD)

MDEQ: To operate an FGD system, it is necessary to place a significant amount of (solid) material handling equipment on site. This would also include a large surface area to store, move and otherwise handle the reagent and spent- reagent materials. This equipment and space might typically be available and designed in an FGD installation such as a new coal-fired electrical generation station which also handles bulk solid materials (coal, e.g.) on routine basis. For this facility, however, none of the required space for solids handling and storage equipment is readily available. There is simply not enough space in MSCC's very narrow footprint to accommodate a significant redesign of the facility in both layout and surface disturbance. Thus, to install and operate an FGD for this facility, not only is an FGD itself necessary, but a complete particulate removal system will be required as well (typically a fabric filter). Thus, the FGD will add new particulate emission sources at this facility; offsetting some of the reduction achieved by the sulfur-removing FGD system.

FGD systems are not typically designed to process high concentrations streams of SO_2 or containing H_2S. EPA suggests that inlet loading of SO_2 is limited to streams with less than 2,000 ppm[12]. Emissions monitoring data reported to DEQ typically show an average SO_2 concentration between 2,000 and 3,000 ppm, with excursions to higher levels. Thus, Montana concluded this technology is not feasible for use at MSCC.

Any FGD system, regardless of the type, will require disposal of the spent reagent. Since space is limited at this site, the disposal needs to take place at a "new" offsite landfill, able and willing to accept the effluent. Thus, in addition to the cost necessary for the FGD, a suitable landfill site would need to be identified and a permit would need to be obtained. There is, in addition, no available land at MSCC's small site. This would be a significant undertaking and not especially productive given other non-FGD processes are available producing lower levels of solid waste.

As discussed above, for wet scrubber FGD, or any so-called 'dry' or semi-dry system involving quench of the hot-incoming Claus off gases, a complete water system, including disposal off-site, would be required. The water content of Claus off gas is necessarily very high compared to coal firing. This corrosive water system and off-site disposal is deemed unnecessary given other alternatives and the potential environmental consequences.

MSCC indicated that, according to their knowledge, no FGD system has been installed at any acid gas processing facility in the US similar to the MSCC plant. This fact makes it clear that an FGD system is not a viable option for consideration. For all the reasons above, it was decided to not pursue the FGD option further in this study and it was dropped from analyses that follow.

ARD: We agree.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Table 19. MT Draft SIP Table 6-28. MSCC SO_2 Control Efficiencies

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)
	SCOT	99.3	570

[12] EPA's Air Pollution Control Technology Fact Sheet, FGD, EPA-452/F-03-034

100 Meter Stack (Sulfur Recovery Unit)	CBA (Sulfreen®)	99.1	443

ARD: In its 2012 FIP analysis, EPA assumed 99.9% control efficiency for the SCOT technology and 99.5% for CBA.[13]

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

Table 20. MT Draft SIP Table 6-29. MSCC SO_2 Cost of Compliance

Source	Potential Control Option	Potential Emission Reduction (tons/year)	Estimated Capital Cost ($1000)	Estimated Annual Cost including Capital Recovery ($1000/year)	Cost Effectiveness ($/ton)
100 Meter Stack (Sulfur Recovery Unit)	SCOT	570	103,655	15,895	$27,882
	CBA (Sulfreen®)	443	48,963	8,424	$18,999

ARD: MSCC assumed a 5.5% interest rate over a 20-year period.[14] The current (November 2021) prime interest rate (recommended for use by EPA's CCM) is 3.25%. The 2021 revision to the CCM[15] assumes a 30-year life in its acid gas scrubber example. MSCC also included property taxes which may be exempted in Montana. We re-evaluated costs with these and other corrected values as discussed below.

SCOT Cost of Compliance

ARD: In the capital cost calculations. MSCC based its Purchased Equipment Costs for the SCOT system on the total capital investment cost for the SCOT system in the 2012 analysis; this resulted in a 31% overestimation of the total capital investment for the SCOT system in MDEQ's current analysis.

ARD: MSCC essentially used its 2012 analysis as the basis for its 2019 analysis, with updates. For example, a note in the 2019 report states: "Capital costs derivation provided on separate page and are based on data from vendor (Jacobs Comprimo Sulfur Solutions) - January, 2012." In the 2012 report, MSCC's consultant included this note:

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[13] EPA's Reasonable Progress Four-Factor Analyses for MSCC, EPA-R08-OAR-2011-0851-0072, Posted Apr 19, 2012

[14] The capital recovery factor was applied to the control options based on a 20-year equipment life expectancy and applying the prime interest rate (5.5% as of December 19, 2018).

[15] **Section 5, SO_2 and Acid Gas Controls,** Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021

Based on vendor estimate of $55 - $60M for two, 126 tpd capacity units. The capital investment was back calculated based on a total capital investment of the median of this range ($57.5M). A retrofit factor of 1.3 was used, resulting in the total capital investment of $74,750,000.

That footnote is based upon the vendor stating that dual standalone 126 ton/day units operating in parallel would cost between 55 and 60 million with these comments:[16]

The cost estimates are for a direct installed unit(s). They generally include the raw equipment cost, installation electrical, ductwork, etc. Jacobs Comprimo reports that the values are in the -25%/+50% range.

Indirect costs were not assumed to be included since they are somewhat plant specific.

Because of the necessity for continued operation, which is required by the client refinery, Option 2 [two identical 126-ton S/day parallel trins] was chosen. the only practical solution would be Option 2. Option 1 endangers the possibility of continued operation in compliance with any emission limits associated with a requirement to install this technology.

ARD: The SCOT "Cost of system(s) + auxiliary equipment" in this 2012 report was less than $26 million. However, in its 2019 report, MSCC has taken that 2012 Total Capital Investment (TCI) of $57.5 million and transformed it into what it calls the "Capital Cost" for the SCOT system. (This is actually the "Absorber + auxiliary equipment cost" using the CCM nomenclature or the "Cost of system(s) + auxiliary equipment" in this 2012 report.) Instead of a TCI of $74,750,000 in 2012, MSCC is now estimating $103,655,000 in 2019. The most direct comparison between the 2012 and 2019 costs is with the Purchased Equipment Costs (PEC). The 2012 PEC was just over $30 million versus the 2019 PEC of just over $66 million.

ARD: In the current iteration of the Montana draft SIP, a new set of estimates has been added under the heading "SCOT Capital and Operating and Cost Estimates." However, the origin of the new costs for application of the SCOT process at MSCC is unclear. There are three fundamental problems with the latest MSCC SCOT cost analysis:

The TCI is a vendor quote cited at $57,500,000 in the footnote in the 2019 report versus 30 – 50 million (2006) Euros for a "reference size" 91-ton S/day application in the latest MSCC report. We request a copy of that vendor quote.

The CCM recommends against using cost information older than five years—the MSCC costs are based upon a 15-year-old vendor quote.

MSCC applied a 1.3 retrofit factor, this requires justification or documentation.

[16] Based on: Email and data exchange with Dennis Koscieinuk and Frank Scheel, Jacobs Comprimo, January - February 2012

ARD: Until these issues are resolved, we can only evaluate the cost-effectiveness of the SCOT process at MSCC based upon our current understanding of the associated costs as follows:

- In an email and data exchange with Dennis Koscieinuk and Frank Scheel, Jacobs Comprimo, January - February 2012, Mr. Scheel said "The cost estimates are for a direct installed unit(s). They generally include the raw equipment cost, installation electrical, ductwork, etc. Jacobs Comprimo reports that the values are in the -25%/+50% range." Mr. Scheel estimated the cost for installing two parallel 126 ton/day units would be between \$55 and \$60 million USD. We assumed a 57.5 million USD TCI as a mid-range value.
- The Chemical Engineering Plant Cost Index (CEPCI) in 2012 was 582.2 and in 2019 the CEPCI was 607.5. We applied the ratio of the CEPCIs to estimate a 2019 TCI = 60 million USD. Amortized over 30 years at 3.25% interest, the Capital Recovery Cost of adding these two SCOT units is about \$3.2 million/yr.
- According to MSCC, the Fixed Operating Cost = 4% of the Capital Cost. (MSCC based this value on a report that no longer is available on the internet.[17]) It appears that MSCC has applied this 4% factor to the "Absorber + auxiliary equipment cost" = \$57.5 million, not to the TCI. Instead, we applied the 4% factor to our estimate of the TCI.
- Instead of the \$15.9 million annual cost estimated by MSCC, we estimated \$8.4 million.
- Instead of the \$28,000/ton average cost-effectiveness estimated by MSCC, we estimated \$9,000/ton.

There is much uncertainty involved in these estimates and we request that MDEQ provide the calculation spreadsheets that support the cost estimates presented by MSCC.

CBA (Sulfreen®) Cost of Compliance

ARD: We reviewed MSCC's cost analysis for the CBA process and found these errors:

- MSCC applied a 1.25 retrofit factor without justification or documentation.
- Instead of the \$8.4 million annual cost estimated by MSCC, we estimated \$6.5 million.
- Instead of the \$19,000/ton average cost-effectiveness estimated by MSCC, we estimated \$9,000/ton.

Table 21. NPS ARD revised MT Draft SIP Table 6-29. MSCC SO2 Cost of Compliance

Source	Potential Control Option	Potential Emission Reduction (tons/year)	Estimated Capital Cost (\$1000)	Estimated Annual Cost including Capital Recovery (\$1000/year)	Cost Effectiveness (\$/ton)
100 Meter Stack (Sulfur Recovery Unit)	SCOT	951	59,998,712	7,830,733	\$8,237
	CBA (Sulfreen®)	444	48,962,840	8,444,398	\$19,035

[17] "Concawe Cost and Cost-Effectiveness, Assessment of Abatement Technology/Techniques for Refineries". Link: http://www.citepa.org/forums/egtei/5-White-refineries.pdf

Factor 2: Time Necessary for Compliance

MDEQ: Montana has concluded that any required controls could be installed by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: The quench system in the SCOT system produces a sour water waste effluent that requires treatment prior to disposal. This effluent would contain hydrogen sulfide, and may contain sulfur and other troublesome species as well, particularly during upsets. MSCC currently does not have sour water treatment facilities nor access to a public sewer system to accommodate such a waste stream. A permissible solution to this problem would have to be engineered if this system were installed at the facility.

MDEQ: SCOT would also require a few non-fuel consumables of significant cost including: catalyst for the reduction stage, MDEA or proprietary blends of amines, corrosion inhibitors, and water treatment chemicals.

ARD: This should be part of the economic analysis.

Factor 4: Remaining Useful Life

MDEQ: A brief history of MSCC is critical to a discussion regarding its remaining useful life. As a summary, the facility began construction in 1955, and has operated continuously since 1956. Estimates vary on the typical useful life of SRU equipment; however, it would be typical to expect plants to last about 40 years or more with careful maintenance and operation. The facility has exceeded the typical expectation for useful life, in part due to careful operation, quality maintenance and continual improvements in reliability. No specific additional life of the sulfur recovery plant can be offered. The facility has operated under a succession of essential contracts relating to raw material supply and gas processing. There is no way to assuredly predict if such contracts will continue or will cease. However, for purposes of planning, it would be reasonable to assume that the facility, which remains serviceable, effective, and reliable today, would continue to operate at least 15 years into the future.

ARD: EPA assumes 30 years for the life of an acid gas scrubber.[18]

Step 5 – Select Reasonable Progress Control/Final State Recommendations:

MDEQ: Montana concurs with the MSCC prepared and submitted four-factor analysis that the technologies evaluated for SO_2 reductions are not cost effective to be required for the second planning period. If the technologies evaluated improve or other technologies become viable, MSCC will need to further evaluate these in future planning periods. No additional SO_2 control is required for the second planning period.

Conclusions & Recommendations

We are seeing cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

[18] **Section 5, SO_2 and Acid Gas Controls,** Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021

The annual average cost effectiveness of adding SCOT at MSCC would be acceptable in the context of the thresholds used by CO and OR and could reduce annual emissions by about 950 tons/year.

The annual average cost effectiveness of adding CBA to MSCC would not be acceptable in the context of the thresholds used by TX, NM, CO, and OR.

Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.10 ExxonMobil Billings Refinery

Summary of NPS Recommendations and Requests for ExxonMobil Billings Refinery

NPS ARD recommends that MDEQ that conduct a full four-factor evaluation of SO_2 emission control opportunities for the ExxonMobil Billings Refinery (Exxon). This facility is a significant source of regional SO_2 emissions that warrants evaluation irrespective of pending litigation and consent decree status.

Our review NO_x four-factor analyses for Exxon finds that there are technically feasible and cost-effective opportunities available to further control NO_x emissions from the facility. The cost of control is generally more economical than estimated in the draft MT SIP when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

Our revised analysis finds that the annual average cost effectiveness of SCR:

- For the KCOB unit would be acceptable in the context of cost thresholds used by TX, NM, CO; and OR and could reduce unit NO_x emissions by almost 70 tons/year.
- For the F-1/F-401 units would be acceptable in the context of the thresholds used by NM, CO, and OR; and could reduce unit NO_x emissions by over 50 tons/year.
- For the F-501 unit would be acceptable in the context of the thresholds used by CO and OR; and could reduce unit NO_x emissions by over 80 tons/year.

We also find that the annual average cost effectiveness of adding SCR to F-201 at Exxon would exceed the cost effectiveness thresholds used by TX, NM, CO, and OR. Additionally, we find that SNCR exceeds the cost thresholds used by these same states for all of the Exxon emission units.

We recommend that MDEQ require technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

ExxonMobil Billings Refinery (Exxon) is located in Billings, Montana, about 146 km northeast of Yellowstone National Park, a Class I area administered by the NPS.

MDEQ: Exxon is one of the four oil refineries in Montana, with three of the four being near Billings, MT. The Exxon Refinery is designed to process a variety of crude slates including those containing high sulfur crude oil. Major process units include: atmospheric and vacuum crude distillation towers, a fluidized catalytic cracking unit (FCCU), a hydrocracker and hydrogen plant, a fluid coker, a naphtha fractionator, a catalytic reformer, an alkylation unit, three hydrotreaters for polishing the naphtha and distillate streams, and a catalytic hydrotreating unit (CHUB). The Exxon Refinery does not have a sulfur recovery unit within the refinery. Refinery gases high in hydrogen sulfide (H_2S) are piped to an off-site sulfur recovery plant owned and operated by the Montana Sulphur and Chemical Company. MSCC extracts sulfur from the sour refinery fuel gas (RFG) and returns sweetened fuel gas to the Billings Refinery. The bulk terminal does not produce SO_2 or NO_x emissions and is not considered in this analysis.

ARD: What is the refinery's daily and annual throughput. Please provide a plantwide emissions inventory.

MDEQ: The analysis focuses on the following units for NOx: the Coker CO Boiler (KCOB), F-1 Crude Furnace/F-401 Vacuum Heater, and the F-551 Hydrogen Plant. Based on a 2015-2016 emissions baseline, the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, and F-551 Hydrogen Plant are responsible for approximately 52% of the total NO_x emissions at the facility. The F-1 Crude Furnace and F-401 Vacuum Heater are two separate units, but vent to a single stack, so are evaluated as one unit for the purpose of this analysis. To address potential costs and controls associated with the smaller refinery process heaters, this analysis also included the F-201 Hydrofiner Heater as a representative smaller process heater.

For the 2015-2016 baseline summary, 75% of the SO_2 emissions are attributed to the Fluidized Catalytic Cracking Unit (FCCU). The Exxon Refinery is currently engaged in an extended demonstration period on a desulfurization (DeSOx) additive while operating the FCCU in Full Burn Operation as required under its EPA Refinery Consent Decree for controlling SO_2 emissions from the FCCU.

ARD: What is the status of the Consent Decree?

MDEQ: Given this SO_2 control strategy (and pending final emission limits) between EPA and the Exxon Refinery, and the significant effort and analysis that went into that process, no further discussion was provided for SO_2 emission reductions at the Exxon Refinery. The balance of the SO_2 emissions are attributed to either the KCOB (during Yellowstone Energy Limited Partnership downtime, particularly in 2016) or small boilers and heaters subject to NSPS Subpart J or other requirements. No additional control is being considered for these units, given the circumstances of the emissions (for the KCOB) and the existing level of control. Future planning periods may evaluate other emitting units for possible emission reduction opportunities.

ARD: In its November 1, 2021 comments to Wyoming, EPA stated:

First planning period litigation is not a basis to forego a four-factor analysis for Wyodak for the second regional haze implementation period. Wyoming must perform a four-factor analysis or provide a reasonable explanation for excluding Wyodak consistent with the Regional Haze Rule, EPA's Guidance, and the Clarifications Memo.

MDEQ required a full Four-Factor Analysis for SO_2 controls at the CHS Laurel Refinery which had baseline SO_2 emissions of 251.2 tons/year versus the 539.4 tons/year SO_2 reported below for Exxon. MDEQ should conduct a Four-Factor Analysis for SO_2 controls at Exxon.

Exxon RepBase and 2028 OTB/OTW Scenarios

MDEQ: Exxon selected the two-year average from 2015-2016 as representative of emissions at the refinery. Montana concurred that this two-year period was reflective of recent normal operation. Exxon also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved if controls were applied.

ARD: Why was 2015–2016 used instead of 2017–2018? What were 2019 & 2020 emissions?

MDEQ: Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 22. MT Draft SIP Table 6-30. Exxon RepBase and 2028 OTB/OTW Emissions

Baseline Period	**Rep. Baseline NOx**	**Rep. Baseline SO_2**	**2028 OTB/OTW NOx**	**2028 OTB/OTW SO_2**
2015-2016	427.4	539.4	427.4	539.4

NO_x Evaluation

Background

MDEQ: The EPA Refinery Consent Decree, in addition to the significant SO_2 emission reductions for units across the facility, required NO_x emissions to be reduced. A NO_x Control Plan for heaters and boilers that required NO_x controls on at least 30% of the heater and boiler capacity greater than 40 MMBtu/h was implemented. Additionally, the Consent Decree required SCR to be installed (and associated emission limit) on the FCCU. NO_x reductions were evaluated and implemented on units where the investment would provide the most efficient emission reduction value. Exxon has demonstrated progress through the Consent Decree and beyond, to reduce NO_x emissions in the recent past.

This NO_x analysis focuses on the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, and F-551 Hydrogen Plant because these four units are responsible for approximately 52% of the NO_x emissions from the plant based on the 2015-2016 emissions baseline. Two other NO_x sources have seen recent emissions control upgrades (F-700 heater with ULNB) and replacement (B-8 heater with ULNB and FGR) under the Consent Decree. The F-700 and B-8 heaters result in 3% (13.27 tons/year) of the 2015-2016 NO_x emissions baseline. Eight other NO_x sources (i.e., small refinery fuel gas-fired heaters less than 40 MMBtu/hr) split the remaining 45% of the NO_x emissions baseline. As mentioned previously, the F-201 Hydrofiner Heater is included in the analysis to show representative costs and controls for the smaller process heaters units less than 40 MMBtu/hr.

Step 1 – Identify All Available Technologies

MDEQ: There are several ways to control NO_x emissions from a boiler or furnace. Some methods utilize combustion modifications that reduce NO_x formation in the boiler/furnace itself, while others utilize add-on control devices at various points in the exhaust path to remove NO_x after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NOx. The identified applicable NO_x control technologies include:

Ultra-Low NO_x Burners with Flue Gas Recirculation
SNCR (only applicable for boilers, see explanation below)
SCR

The NO_x basis (the current actual emissions referred to as "uncontrolled emissions" in the EPA cost control spreadsheet) for the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551 Hydrogen Plant, and F-201 Hydrofiner Heater is 0.191, 0.110, 0.107, 0.115 pound per million British Thermal Unit (lb/MMBtu), respectively. These emissions are derived from the pound per million cubic feet emission factor used in annual reporting converted using actual refinery fuel gas heating values.

ULTRA-LOW NO_X BURNERS WITH FLUE GAS RECIRCULATION

MDEQ: Combustion controls are features of the boiler that reduce the formation of NO_x at the source. Ultra-Low NO_x Burners are a common combustion control, particularly for new boilers, and typically include Flue Gas Recirculation. Because of the intrinsic nature of both controls (often used in conjunction), they are generally installed in new boilers. While retrofits have occurred (and did, in specific instances during the EPA Refinery Consent Decree NO_x reductions), they generally occurred on smaller, newer, low burner count units. (Note: The B-8 Boiler was a full replacement with UNLB and FGR).

Based on corporate and unit specific information, F-1 Crude Furnace/F-401 Vacuum Heater would not be candidates for ULNB/FGR because of the age of the furnaces. If such an upgrade were required, the furnaces would be replaced, at an estimated cost of $10-$20 million per boiler (F-1 at the higher end, F-401 at the lower end). The F-551 Hydrogen Plant would also not be a candidate for UNLB/FGR because of the high number of burners (80). Replacement of 80 burners would essentially require a rebuild of the furnace. Retrofitting the KCOB or the F-201 Hydrofiner Heater with UNLB/FGR is a potential option, however cost data is generally unavailable.

ARD: What is the cost-effectiveness of replacement?

MDEQ: For the F-201 Hydrofiner Heater and KCOB, the Billings Refinery provided an estimate of UNLB retrofit installation based on actual average costs incurred for similar refinery units in the ExxonMobil fleet.

ARD: More information is needed to support this statement.

MDEQ: Incorporation of FGR is not included in the estimate because it would require a boiler reconfiguration (and potentially reconstruction).

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

MDEQ: The viability of SNCR is directly related to combustion temperature (typically between 1,550°F and 1,950°F); therefore, the application of this technology to furnaces/heaters is not technically feasible, as they operate at much lower temperatures (600-700°F). SNCR was analyzed only for the KCOB, and not for the F-1 Crude Furnace/F-401 Vacuum Heater, the F-551 Hydrogen Plant, or the F-201 Hydrofiner Heater.

The median reductions for urea based SNCR systems in various industry source categories range from 25 to 60 percent. Additional industry-specific unit information included in the SNCR White Paper[19] provided boiler size and associated NO_x reductions; particularly in the "Refinery Process Units and Industrial Boiler" section, for units less than 200 MMBtu/hr (the KCOB is rated at 146 MMBtu/hr). The 200 MMBtu/hr was used as a logical cut-off for smaller industrial boilers, with ranges estimated between 40 and 62.5 percent NO_x reduction. An average reduction of 58.5 percent was used in the cost efficiency calculations, for a resulting/predicted exit NO_x emission factor of 0.079 lb/MMBtu at the KCOB.

ARD: SNCR control efficiency is related to uncontrolled NO_x emissions. We applied the relationship in Figure 1.1c. in EPA's Control Cost Manual (CCM) and estimated 20.6% NO_x control efficiency for this unit.

MDEQ: The costs provided for SNCR in the four-factor analysis were calculated using EPA's SNCR Cost Calculation Spreadsheet and use the "retrofit factor" of 1 – average retrofit.

ARD: We agree.

MDEQ: The Spreadsheet states that its use is particularly for boilers (coal-, oil-, and natural gas-fired) with maximum heat capacities greater than or equal to 250 MMBtu/hr. The KCOB has additional difficulty with respect to boiler ductwork, etc. because of its direct proximity to the coker unit and shared piping/ductwork with that unit. Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, the involvement with the coker unit, and the economies of scale described above, the Billings Refinery believes that the costs calculated are highly conservative (i.e., costs are estimated low). EPA's estimates compared to actual costs incurred for similar refinery units in the ExxonMobil fleet are quite low and do not consider the significant and unique complexities associated with retrofitting refinery units.

SELECTIVE CATALYTIC REDUCTION (SCR)

MDEQ: The controlled SCR emissions rates used in the analysis were based on a 95% control efficiency. Because ammonia is most commonly used (and is the default for the EPA's SCR Cost Calculation Spreadsheet), it was used in the reagent calculations for the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551 Hydrogen Plant, and the F-201 Hydrofiner Heater.

As previously discussed for SNCR, there is an efficiency of scale associated with pollution control equipment installation. Because the cost calculator is based on units with a heat capacity greater than 250

[19] Institute of Clean Air Companies (ICAC), Selective Non-Catalytic Reduction (SNCR) for controlling NOx Emissions; White Paper. Prepared by the SNCR Committee of ICAC. February 2008. Available at: https://cdn.ymaws.com/icac.siteym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf

MMBtu/hr (and only one unit, the combined F-1 Crude Furnace/F-401 Vacuum Heater is in that size range at 280 MMBtu/hr), those efficiencies are included in the EPA spreadsheet estimates. The costs provided for SCR in the four-factor analysis that follows are calculated using EPA's SCR Cost Calculation Spreadsheet also use the "retrofit factor" of 1 – average retrofit.

ARD: We agree.

MDEQ: Based on the boiler size, the less-common refinery-fuel gas, the potential for higher retrofit costs, and the economies of scale described above, the Billings Refinery believes that the costs calculated for SCR are also highly conservative (i.e., costs are estimated low). EPA's estimates compared to actual costs incurred for similar refinery units in the ExxonMobil fleet are quite low and do not take into account the significant and unique complexities associated with retrofitting refinery units.

ARD: We agree with MDEQ's selections.

Step 2 – Eliminate Technically Infeasible Options

MDEQ: None of the options presented were deemed technically infeasible.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: The control effectiveness for the reviewed technologies ranged from approximately 60 percent for SNCR up to 95 percent for SCR. The control efficiencies are shown in Table 6-31.

ARD: SNCR control efficiency is related to uncontrolled NO_x emissions. We applied the relationship in Figure 1.1c. in EPA's Control Cost Manual (CCM) and estimated 20.6% NO_x control efficiency for this KCOB.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: 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 KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551 Hydrogen Plant, and the F-201 Hydrofiner Heater were taken from the baseline 2015 and 2016 annual emission inventory years it relates to this planning period.

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. The Exxon cost effectiveness estimates are based on similar unit upgrades (or averages of similar unit upgrades, with allowances for unique Billings space or needs) elsewhere in the ExxonMobil refinery fleet. Specific retrofit costs would require a detailed engineering analysis of the actual site (for space considerations), unit, and process considerations.

Table 23. MT Draft SIP Table 6 24. Estimated Costs of NOx Control Options for the Billings Refinery, ranked by Control Efficiency

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	EPA Total Annual Cost (in 2018 dollars)a	Cost Effectiveness ($/ton) based on EPA spreadsheet/ retrofit factora	Estimated ExxonMobil Retrofit Factore	Anticipated Actual Cost Effectiveness ($/ton) b
KCOB (146 MMBtu/hr, refinery fuel gas fired)	SNCR	58.5	30	$231,203	$7,698	--	--
	UNLB	~85	62	--d	--d	--	$5,800c
	SCR	95	67	$438,842	$6,564	3.7	$24,300
F-1/F-401 (280 MMBtu/hr, refinery fuel gas fired, total)	SCR	95	79	$687,812	$8,732	3.7	$32,300
F-551 (160 MMBtu/hr, refinery fuel gas fired)	SCR	95	51	$474,103	$9,290	3.7	$34,400
F-201(36 MMBtu/hr, refinery fuel gas fired)	UNLB	~78	~7	--d	--d	--	$31,100c
	SCR	95	~9	$169,512	$18,919	3.7	$70,000

a. Based on EPA Cost Control Spreadsheets 2019.
b. Based on ExxonMobil corporate project information.
c. The UNLB cost assumes no major physical changes to boiler or boiler configuration (e.g., due to spacing of burners). d. As discussed in Section 5.2.1, EPA does not have ULNB costs in its cost control manual at this time.
e. ExxonMobil retrofit factors ranged from approximately 3.7 to 10.

ARD: EPA's Control Cost Manual (CCM) now recommends use of the current prime interest rate (3.25% as of November 2021) and 25-year life for SCR on industrial applications. The table below reflects our use of the CCM workbooks to estimate costs of applying SNCR or SCR to the four NO_x emission sources selected by MDEQ. We disregarded the Exxon/Mobil retrofit factors for reasons discussed below.

We recognize that determining if a retrofit factor is appropriate (and, if so, what that factor should be) is not a simple process. However, Exxon has not provided documentation justifying selected retrofit factors, some of which exceed the maximum value (1.5) recommended by EPA. We recommend that the procedure outlined by William Vatavuk[20] on pages 59-62 in his book Estimating Costs of Air Pollution Control[21] be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. In the absence of such an analysis, we assumed a retrofit factor = 1.0.

Our application of the CCM workbooks yielded the results below.

Table 24. NPS ARD Estimated Costs of NO_x Control Options for the Billings Refinery

Source	Potential Control Option	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	EPA Total Annual Cost (in 2019$)	Cost Effectiveness ($/ton) based on EPA
KCOB (146 MMBtu/hr, refinery fuel gas fired)	SNCR	21	11	$175,565	$16,648
	SCR	95	67	$331,072	$4,952
F-1/F-401 (280MMBtu/hr, refinery fuel gas fired, total)	SCR	95	82	$525,858	$6,411
F-551 (160MMBtu/hr, refinery fuel gas fired)	SCR	95	51	$359,706	$7,048
F-201(36MMBtu/hr, refinery fuel gas fired)	SCR	95	9	$126,071	$14,071

Factor 2: Time Necessary for Compliance

MDEQ: Exxon relies on the consistent operation of the units which were evaluated for the four-factor analysis. Therefore, any major retrofits or maintenance on major refinery units are scheduled during periodic maintenance turnarounds. Any major control installation at affected units would have to wait until either the estimated 2026 Hydrogen Plant/Hydrocracker turnaround (affecting the F-551 Heater) or the estimated 2025 FCCU/Alkylation Unit turnaround. The retrofit of smaller process heaters (such as the F-201 Hydrofiner Heater) may allow for implementation outside of major turnarounds, but such efforts would require a similar level of planning as the major units because of the interdependence of refinery systems.

EPA does not provide a specific time necessary for compliance basis for replacement of existing burners/boiler configurations with ULNB/FGR. Exxon estimated SNCR would require approximately 3-5 years for design, permitting, financing, etc. through commissioning.

For SCR, EPA states in its Control Cost Manual, "In retrofit installations, new ductwork is required to integrate the SCR system with the existing equipment." Because the KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551, F-201 Hydrofiner Heater are primarily refinery fuel gas-fired units and have

[20] William Vatavuk was a major contributor to EPA's Control Cost Manual.
[21] https://books.google.com/books?id=17DVRbiisZYC&pg=PA61&lpg=PA61&dq=william+Vatavuk+retrofit+factors&source=bl&ots=p83DC8wi5f&sig=ACfU3U2Cq_xXh2ymTbn45vdUF_oEYPb7Wg&hl=en&sa=X&ved=2ahUKEwjIsvDmzZHpAhWRYDUKHe4tAeQQ6AEwAHoECAoQAQ#v=onepage&q=william%20Vatavuk%20retrofit%20factors&f=false

negligible particulate emissions, consideration of high-dust SCRs would not be necessary, and the focus would be on either low-dust or tail-end installations (tail-end refers to following all pollution control devices; for the units in question, the options would be essentially the same). Exxon estimated SCR would require approximately 3-5 years for design, permitting, financing, etc. through commissioning. If PSD permitting is triggered on the basis of formation of condensable particulate matter from the SCR, the timeline would be extended beyond that estimate.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: In general, the use of combustion controls for reducing NO_x formation can in turn cause an increase in CO emissions.

SCR and SNCR both can result in ammonia slip. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, (NH4)2SO4. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste.

ARD: These issues are common to this control technology. Many catalyst vendors provide catalyst disposal/regeneration services.

Factor 4: Remaining Useful Life

MDEQ: None of the units considered (KCOB, F-1 Crude Furnace/F-401 Vacuum Heater, F-551, or F-201 Hydrofiner Heater) are planned for retirement at this time. Therefore, the remaining useful life of the sources is assumed to be 20 years.

ARD: In the absence of federally enforceable limits on the life of these boilers, we assumed that they would operate for the 25-year SCR life.

Step 5 – Select Reasonable Progress Control

SO2

MDEQ: Montana concurs with the Exxon prepared and submitted four-factor analysis that the recent and on-going efforts to reduce SO_2 reductions are adequate for this second planning period. The success of this determination will be measured when the next round of regional haze planning is completed.

ARD: MDEQ should describe the current status of these efforts. MDEQ required a full Four-Factor Analysis for SO_2 controls at the CHS Laurel Refinery which had baseline SO_2 emissions of 251.2 tons/year versus the 539.4 tons/year SO_2 reported for Exxon. MDEQ should conduct a Four-Factor Analysis for SO_2 controls at Exxon.

NOx

MDEQ: Montana concurs with the Exxon prepared and submitted four-factor analysis that all the NO_x reduction technologies analyzed, with cost effectiveness ranging from $5,800-$70,000, are cost prohibitive at this time. No additional NO_x control is required for the second planning period. NO_x emissions remain significant at approximately 430 tons/year. Future planning periods may look at other smaller emitting NO_x units for emission reductions.

ARD: These costs are overestimated. Decision criteria should be publicly available.

Conclusions & Recommendations

- MDEQ should conduct a Four-Factor Analysis for SO_2 controls at Exxon.
- We are seeing cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The annual average cost effectiveness of adding SNCR at Exxon would not be acceptable in the context of the thresholds used by TX, NM, CO, and OR.
- The annual average cost effectiveness of adding SCR to KCOB at Exxon would be acceptable in the context of the thresholds used by TX, NM, CO, and OR. Addition of SCR could reduce unit NO_x emissions by almost 70 tons/year.
- The annual average cost effectiveness of adding SCR to F-1/F-401 at Exxon would be acceptable in the context of the thresholds used by NM, CO, and OR. Addition of SCR could reduce unit NO_x emissions by over 50 tons/year.
- The annual average cost effectiveness of adding SCR to F-501 at Exxon would be acceptable in the context of the thresholds used by CO and OR. Addition of SCR could reduce unit NO_x emissions by over 80 tons/year.
- The annual average cost effectiveness of adding SCR to F-201 at Exxon would not be acceptable in the context of the thresholds used by TX, NM, CO, and OR.
- Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.11 CHS Inc. Refinery Laurel

Summary of NPS Recommendations and Requests for CHS Inc. Refinery Laurel

NPS ARD review of the four-factor analysis conducted for Cenex Harvest States Cooperative Inc. (CHS) finds that there are technically feasible and cost-effective opportunities available to further control NO_x emissions from the facility. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

Our revised cost analysis using 90% SCR control efficiency and a corrected capital recovery factor (CRF) finds that SCR is a cost effective option for controlling NO_x emissions from all three of the primary emission units at CHS using the thresholds established by CO and OR. SCR is most cost effective for the Platform Heater, at less than $5,000/ton it would meet the cost effectiveness thresholds set by all of the states listed. SCR could reduce NO_x emissions from the CHS Platform Heater by over 80 tons/year, from the Main Crude Heater by almost 40 tons/year, and from Boiler #9 by over 25 tons/year.

We recommend that MDEQ require the most effective of the technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

Cenex Harvest States Cooperative Inc. (CHS) is located in Laurel, Montana, about 120 km northeast of Yellowstone National Park, a Class I area administered by the NPS.

MDEQ: Refineries contain many small emitting units that, in aggregate, contribute to emissions of SO_2 and/or NO_x at the facility. Because of this, Montana determined that it was impractical to perform a four-factor analysis on each individual emitting unit. Montana and CHS agreed on a ranking of the highest emitting units for both NO_x and SO_2 that could be evaluated in the four-factor analysis. Doing so provided the information necessary to determine opportunities for emissions reductions at the facility.

ARD: What is the refinery's daily and annual throughput. Please provide a plantwide emissions inventory.

MDEQ: This analysis focuses on the following subset of emitting units at CHS: Main Crude Heater (NOx), the Platformer Heater (NOx), Boiler #9 (NOx) and the Main Refinery Flare (SO_2).

CHS RepBase and 2028 OTB/OTW Scenarios

MDEQ: CHS selected the two-year average from 2017-2018 as representative of baseline emissions. Montana concurred that this two-year period was reflective of recent normal operation. CHS also selected a future year 2028 OTB/OTW scenario that was used to calculate the cost per ton of emission reduction achieved from applying controls. The specific updates to emitting units that were adjusted to determine the 2028 OTB/OTW scenario and reasoning are as noted:

Platformer Recycle Compressor: The natural gas fired driver for this compressor was replaced with an electric motor during 2018. This resulted in a reduction in NO_x emissions from the 2017-2018 baseline.

#2 Crude Unit Vacuum Heater: This refinery fuel gas (RFG) fired process heater is nearing the end of its serviceable life. It will be replaced prior to 2028 with a heater that includes ultra-low NO_x burners. This will result in a reduction in actual NO_x emissions from the 2017-2018 baseline.

Stationary Emergency Engines: Emissions from stationary emergency engines were first added to the refinery emissions inventory in 2018. A small increase in actual NO_x emissions from the 2017-2018 baseline will result because they were not reported in 2017.

Main Refinery Flare: It is conservatively estimated that SO_2 emissions from the main refinery flare will decrease by 20% from the 2017-2018 baseline by 2028 as a result of ongoing air pollution control programs, including optimization and increased utilization of the FGRS and the ongoing work practices required by applicable regulations.

Representative baseline and 2028 OTB/OTW emissions for the facility are as follows:

Table 25. MT Draft SIP Table 6-32. CHS RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	408.6	251.2	393.0	215.0

ARD: What were 2019 & 2020 emissions?

To further refine the analysis, the actual base emissions for the four units were evaluated for either NO_x or SO_2 reductions. The baseline emissions for the units analyzed are as follows:

Table 26. MT Draft SIP Table 6-33. CHS Baseline Emissions by Emitting Unit

Source	Pollutant	2017-2018 Baseline, TPY
Main Crude Heater	NOx	43.6
Platformer Heater	NOx	91.4
#9 Boiler	NOx	29.3
Main Refinery Flare	SO_2	181.6

ARD: What are the hourly and annual heat inputs for these three units?

SO_2 Evaluation

Step 1 – Identify All Available Technologies

MDEQ: The Main Refinery Flare receives flow from two separate flare headers (i.e., the primary and non-recoverable headers) that are designed to safely accumulate and transfer gases from the refinery processes to the flare for combustion. In addition to hard-piped connections that support normal process operating conditions, the flare gas headers also have connections that support equipment depressurization and purging for maintenance activities, such as startups, shutdowns, and maintenance turnarounds.

The primary flare header delivers vent gas from the process units to either the flare gas recovery system (FGRS) or to the flare stack. Under normal refinery operations, the FGRS is used to direct recovered flare gases to an amine unit for removal of H_2S prior to use in the refinery fuel gas (RFG) system. Although the intent is to maximize the amount of flare gas recovered, certain maintenance activities (e.g. steaming, pressure testing, and nitrogen purging equipment to the flare to ensure safe working conditions) may require bypassing the FGRS to avoid upsetting the RFG system. The FGRS is also bypassed during events when the volume of vent gas that is relieved into the flare header system exceeds the capacity of the FGRS. Such events include emergency releases, process upsets, or unit startups/shutdowns. During an event, the pressure of the gases in the flare header exceeds the back-pressure exerted on the header by a liquid seal and the gases bypass the seal to the flare where they are combusted. The frequency and duration of these activities and events are highly variable and may last for several hours to several days or weeks depending on the specific situation.

ARD: What is the H_2S content of the refinery gas? How efficient is the amine unit?

MDEQ: The non-recoverable flare header is used to transfer hydrogen-rich gases and excess RFG to the flare. The hydrogen-rich streams are considered non-recoverable due to their low net heating value (i.e., Btu/set), which has the potential to cause an upset in the RFG system. The sulfur content of the vent gases in the non-recoverable flare header is minimal. As a result, the amount of SO_2 resulting from the combustion of non-recoverable gases is small.

Collectively, all the equipment that is connected to the FGRS and main flare make up the "system" where SO_2 emissions can be reduced through additional equipment, improved operating procedures and overall better process control.

A review of precedents and requirements for flares in the RBLC database, permits, EPA/DOJ consent decrees, and regulations identified flare gas recovery and work practices as potential SO_2 control measures. Work practices identified include the following:

- Flare management plans
- Waste gas minimization plans
- Root cause/corrective action programs
- Flare monitoring requirements
- Proper equipment design
- Proper maintenance practices

Step 2: Eliminate Technically Infeasible Options

MDEQ: All the identified control measures are considered to be technically feasible for control of SO_2 from the Main Refinery Flare. The FGRS has been in operation on the Main Refinery Flare since November 2015. It was identified as one element of BACT for the Main Refinery Flare during a 2014 minor modification permit action. In addition, each of the identified work practices are already in place due to the various regulations that are applicable to the Main Refinery Flare, as follows:

- NSPS subpart Ja at§ 60.103a(a) and NESHAP subpart CC at§ 63.670(0)(1) each require development of a written flare management plan (FMP). The following information is specifically required to be included in or referenced in the FMP:
- Listing of all process units, ancillary equipment, and fuel gas systems that are connected to the flare header system;
- A flare minimization assessment;
- Descriptions of all flare components and design parameters;
- Specifications for all required monitoring instrumentation;
- A baseline flow evaluation; and
- A description of procedures to reduce flaring during planned startups and shutdowns, during imbalances of the fuel gas system, and during outages of a FGRS.
- A completion of a root cause/corrective action analysis when the 24-hour total SO_2 from the flare exceeds 500 pounds and/or when the 24-hour total flare flow is greater than 0.5 MMSCF above the baseline.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: No control measures beyond what are already in place were identified. Each of the work practices identified above together function as a means of minimizing SO_2 emissions. However, additional SO_2 reductions at the Main Refinery Flare are anticipated as part of ongoing air pollution control programs.

Step 4 – Evaluate Impacts and Document Results

Factor 1 – Cost of Compliance Main Refinery Flare SO_2

MDEQ: No control measures beyond what are already in place were identified in this analysis. The total capital cost of the FGRS installed in 2015 was greater than $50MM. Continuing to operate the FGRS with the work practices will continue to provide SO_2 control while also allowing for continued optimization of the entire system as additional process knowledge is incorporated to provide further SO_2 reductions.

Factor 2 – Time Necessary for Compliance Main Refinery Flare SO_2 Controls

MDEQ: The FGRS is already in place and will continue to operate.

Factor 3 - Energy and Non-Air Quality Environmental Impacts of Compliance Main Refinery Flare SO_2

MDEQ: No control measures beyond what are already in place were identified in this analysis and therefore no new additional impacts are identified.

Factor 4 - Remaining Useful Life- Main Refinery Flare SO_2 Controls

MDEQ: No control measures beyond what are already in place were identified in this analysis. The Main Refinery Flare and FGRS began operation in 2015. It is expected that the flare and FGRS have a remaining useful life greater than 20 years.

Step 5 – Select Reasonable Progress Control

MDEQ: No control measures beyond those already in place at the Main Refinery Flare were identified in the Four-Factor Analysis. CHS believes that SO_2 emissions from the Main Refinery Flare will decrease by at least 20% from the 2017 - 2018 baseline by 2028 as a result of ongoing programs and work practices. These programs will continue to identify opportunities to reduce vents to the flare and to increase utilization of the FGRS. Following are two examples of recently identified opportunities:

Evaluation of flare emissions during maintenance activities identified the potential benefit of additional online analyzers to better identify flare gases that may be compatible with the RFG system. These analyzers have been installed.

A piping modification is being implemented to allow for recovery and amine treatment of certain flare gases that aren't currently being recovered because they don't meet RFG specifications. Although these recovered gases will be returned to the flare after treatment, SO_2 emissions at the flare will be significantly reduced.

As a result of these ongoing programs, it can be concluded that enforceable emissions limitations, compliance schedules, and other measures are already in place, are providing SO_2 emission reductions at the facility.

NO_x Evaluation

MDEQ: The Main Crude Heater was installed in 1961 and is located in the #1 Crude Unit. It is a natural draft horizontal cabin type heater with a top mounted convection section and stack and has been retrofitted with an air pre-heat system. It is equipped with 24 burners located along the sidewalls that fire horizontally along the floor of the firebox. It has a design heat input of 142 MMBtu/hr (HHV) and is fired with RPG. In 2012, the burners were replaced with low NO_x burners that had a burner vendor guaranteed NO_x emissions rate of 0.08 lb/MMBtu (HHV). Because the heater does not have CEMs and stack testing has not been required, a NO_x emission rate of 0.1 lb/MMBtu (HHV) has been conservatively used as the basis for emissions calculations since completion of the 2012 burner retrofit.

The Platformer Heater was installed in 1973 and is located in the Platformer Unit. It is a natural draft, four cell heater with a common convection section that generates steam. There are 36 burners fired horizontally in three cells from both end walls (12 burners per cell) and six (6) floor fired burners in the fourth cell. It has a design heat input of 190.4 MMBtu/hr (HHV) and is fired with RFG. The NO_x emission rate from the heater has been conservatively assumed to be equal to the AP-42 emissions factor of 280 lb/106 scf (approximately 0.275 lb/MMBtu, HHV) for large wall-fired boilers. A performance test completed in 2002 indicated an actual NO_x rate of 0.163 lb/MMBtu.

Boiler #9 was installed in 1978 and is one of four steam generating boilers located at the Laurel refinery. It is a natural gas fired unit with one burner and has a design heat input of 98 MMBtu/hr (HHV). The assumed NO_x emissions rate from the boiler is based on the AP-42 emission factors of 100 lb/106 scf (approximately 0.098 lb/MMBtu, HHV) for small boilers. More recently, Boiler #9 is planned for replacement but will continue in operation until a new boiler comes on-line in its place. More importantly, the replacement boiler will be permitted under Montana's PSD program and following BACT.

ARD: Can the replacement boiler net out of PSD review?

Step 1 – Identify All Available Technologies

MDEQ: Based on a review of recent NO_x control precedents for gas fired process heaters two fundamental categories of NO_x controls were identified: low NO_x burners (LNB) or ULNB, and post-combustion catalytic control to selectively reduce NO_x emissions (SCR). In addition to these controls, external flue gas recirculation (FGR) was identified as a potential NO_x control for boilers. The NO_x control effectiveness of ULNB technology makes use of what is called internal FGR.

Additional controls that are applied to the control of NO_x from other types of combustion sources include: SNCR, nonselective catalytic reduction (NSCR), and EMx™. These controls, which are potentially applicable via technology transfer, are also considered.

Technical Feasibility of Available NO_x Control Technologies

MDEQ: LNBs/ULNB, and SCR are considered to be demonstrated on gas fired refinery process heaters. In addition to LNBs/ULNB, and SCR, FGR is also considered demonstrated on boilers. As a result, these controls are considered further by this analysis. The technical feasibility of FGR to process heaters, and SNCR, NSCR, and EMx™ to both process heaters and boilers are evaluated further using the previously discussed criteria: applicability, availability, and demonstrated in practice.

ARD: We agree with MDEQ's selection of control technologies.

Step 2 – Eliminate Technically Infeasible Options

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

MDEQ: Because SNCR's ability to achieve NO_x reduction requires operation of the combustion source within specific ranges it has previously only been applied to the control of NO_x emissions from sources that operate within well-defined operating ranges and that do not rapidly vary across those ranges such as base-loaded boilers and FCCUs. Refinery process heaters operate across much wider ranges. As a result, SNCR has not been widely applied within the refinery industry and is not considered feasible for the process heaters. Boiler #9 is operated over a wide range of loads. As a result, SNCR is eliminated from further consideration.

ARD: We agree.

NON-SELECTIVE CATALYTIC REDUCTION (NSCR)

MDEQ: NSCR is used to reduce NO_x emissions in the exhaust of automotive engines and stationary internal combustion engines. NSCR systems are comprised of three different catalyst types used in series. The first catalyst in the series is a reducing catalyst that is used to react unburned hydrocarbon in the exhaust with NO_x in the exhaust. Tuning the engine to run fuel rich creates the unburned hydrocarbon. The next catalyst in the series is an oxidizing catalyst that is used to oxidize the unburned fuel to CO and water and the final catalyst, which is also an oxidizing catalyst is used to oxidize any remaining CO. NSCR has only been applied to engines because it is impractical to tune a fired combustion source such as a process heater to combust in a fuel rich manner. As a result, this control type is considered to be infeasible for the proposed application and removed from further review.

ARD: We agree.

EMX™

MDEQ: The EMx™ system (formerly referred to as SCONOX™) is an add-on control device that simultaneously oxidizes CO to CO_2, VOCs to CO_2 and water, NO to NO_2 and then adsorbs the NO_2 onto the surface of a potassium carbonate coated catalyst. The EMx™ system does not require injection of a reactant, such as ammonia, as required by SCR and SNCR and operates most effectively at temperatures ranging from 300°F to 700°F.

There are currently six EMx™ units in commercial operation with the U.S. All are on natural gas-fired combustion turbines of 45 MW or less. There are no known installations on process heaters or boilers. There are a number of differences between the operation and flue gas characteristics of combustion turbines and CHS's candidate process heaters and boiler considered by this analysis. Specifically, combustion turbines are essentially constant flue gas flow combustion devices no matter what the load.

Process heater and boiler gas flow rates are directly proportional to load. The impact on the load following ability of the EMx™ is unknown with respect to process heater and boiler applications. Additionally, the concentration of NOx/NO_2 in the flue gases from the process heaters are much higher than that of the combustion turbine flue gases. This is due to the high oxygen content of the combustion turbine flue gas (~15% 0_2) relative to a process heater/boiler flue gas (~3% 0_2). The impact of the flue gas oxygen content and NOx/NO_2 concentration on the EMx™ is unknown. Finally, the combustion turbines where EMx™ has been demonstrated have all been fired with natural gas. Of the CHS sources included in this analysis, only Boiler #9 is natural gas fired. Based on the above factors the use of EMx™ to control NO_x emissions from the selected CHS process heaters and boiler is considered technically infeasible and this technology is eliminated from further consideration.

ARD: We agree.

MDEQ: The following technologies are carried forward for further consideration.

Table 27. MT Draft SIP Table 6-34. CHS Technically Feasible Technologies to Reduce NOx

Process Heaters	Boilers
LNB/ULNB LNB/ULNB followed by SCR	FGR LNB/ULNB LNB/ULNB followed by SCR

ARD: WE recommend that MDEQ evaluate addition of SCR only.

MDEQ: The NO_x emission rate achievable as part of a heater or boiler retrofit is dependent upon the inherent design of the heater. Although it may be technically feasible to retrofit an existing heater/boiler with a control, NO_x emission rates that are achievable on a new heater/boiler may not be achievable through a retrofit installation. Table 6-35 identifies the NO_x emission rates expected to be achievable for the identified process heaters and boiler as a result of installation of ULNB (heater) or FGR+ULNB (boiler). The table also notes the NO_x reduction expected from the retrofit.

Table 28. MT Draft SIP Table 6-35. CHS ULNB Achievable NO_x Levels - Process Heaters and Boilers

	Main Crude Heater	Platformer Heater	Boiler #9
Baseline NOx, lb/MMBtu	0.1	0.275	0.098
Post Retrofit NOx, lb/MMBtu	0.05	0.04	0.04
Baseline NOx, tons/year	43.6	91.4	29.3
NO_x Reduction, tons/year	21.8	78.1	17.3

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: An analysis of recent SCR based precedents for new units where the SCR's placement can be integrated into the heater's design indicated NO_x reductions of 85 to 95 percent on an annual average basis. As a result, due to the retrofit related issues of installing an SCR, a design level NO_x control of 85% was applied as part of this analysis.

ARD: The controlled SCR emissions rates used in MDEQ's Exxon analysis were based on a 95% control efficiency. We assumed 90% control for our analysis of SCR on these units.

- Comparing the baseline emissions to the emission reductions from ULNB+SCR yields ULNB+SCR control efficiencies of 92% for the Main Crude Heater, 98% for the Platformer Heater, and 94% for Boiler #9.

- Comparing the ULNB emissions to the emission reductions from ULNB+SCR yields SCR control efficiencies of 85% for the Main Crude Heater, 14% for the Platformer Heater, and 59% for Boiler #9.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: CHS calculated the costs for NO_x for the two process heaters and boiler evaluated. A summary of the estimated costs is presented in Table 6-36 The costs presented were developed in accordance with EPA's Air Pollution Control Cost Manual (CCM) methodology. Capital costs were escalated to 2018 dollars using the Chemical Engineering Plant Cost Index.

Table 29. MT Draft SIP Table 6-36. Summary of the Cost of Compliance Associated with Application of ULNB and SCR on Identified Process Heaters and Boilers

PARAMETERS	**Main Crude Heater**	**Platformer Heater**	**Boiler #9**
ULNB			
Total Capital Requirement, $	2,826,000	8,488,000	3,249,000
Annual O&M Costs, $	71,000	212,000	81,000
Capital Recovery Costs, $	267,000	801,000	307,000
Total Annual Costs, $	338,000	1,013,000	388,000
SCR			
Total Capital Requirement, $	6,005,000	6,192,000	5,307,000
Annual O&M Costs, $	263,100	283,400	230,000
Capital Recovery Costs, $	566,900	584,500	501,000
Total Annual Costs, $	830,000	867,900	731,000
NO_x Emissions, tons/yr			
Actual Emissions (2017-2018)	43.6	91.4	29.3
Emissions w/ULNB	21.8	13.3	12.0
Emissions w/ULNB + SCR	3.3	2.0	1.8
NO_x Reductions			
ULNB	21.8	78.1	17.3
ULNB+SCR	40.3	89.4	27.5
Cost Effectiveness, $/ton			
ULNB	15,500	13,000	22,400
ULNB+SCR	27,800	21,000	39,000

ARD: CHS used an out-dated version of the CCM and applied a 7% interest rate and a 20-year useful life for the control equipment. The CCM recommends use of the prime interest rate—currently 3.25%-- and 25-year life for SCR, which yields a CRF = 0.0590. Our results are shown below.

Table 30. ARD Revised MT Draft SIP Table 6-36. Summary of the Cost of Compliance Associated with Application of ULNB and SCR on the Identified Process Heaters and Boilers

PARAMETERS	**Main Crude Heater**	**Platformer Heater**	**Boiler #9**
Estimate by	**ARD**	**ARD**	**ARD**
Elevation (ft)	3300	3300	3300
Installation Date	1961	1973	1978
Design Heat Input (mmBtu/hr)	142	190.4	98
Emissions			
2017-2018 Baseline, TPY	43.6	91.4	29.3
NO_x Emission Rate (lb/mmBtu)	0.1	0.275	0.098
Emissions w/ULNB, TPY	21.8	13.3	12
Post Retrofit NO_x (lb/mmBtu)	0.05	0.04	0.04
NO_x Reduction ULNB	21.8	78.1	17.3
NO_x Reduction (%)	50%	85%	59%
Emissions w/SCR, TPY	4.36	9.97	2.99
Post Retrofit NO_x (lb/mmBtu)	0.010	0.030	0.010
NO_x Reduction SCR	39.2	81.4	26.3
NO_x Reduction (%)	90%	89%	90%
Emissions w/ULNB + SCR, TPY	3.3	2.0	1.8
Post Retrofit NO_x (lb/mmBtu)	0.006	0.006	0.006
NO_x Reduction ULNB+SCR	40.3	89.4	27.5
NO_x Reduction (%)	92%	98%	94%
Costs			
Interest Rate	0.0325	0.0325	0.0325
Remaining Useful Life (yr)	25	25	25
Capital Recovery Factor	0.05904	0.05904	0.05904
ULNB			

Total Capital Requirement, $[1]	$ 2,826,000	$ 8,488,000	$ 3,249,000
Annual O&M Costs, $	$ 71,000	$ 212,000	$ 81,000
Capital Recovery Factor	0.0590	0.0590	0.0590
Capital Recovery Costs, $	$ 166,845	$ 317,735	$ 191,819
Total Annual Costs, $	$ 237,845	$ 399,035	$ 272,819
NO_x Reduction ULNB	21.8	78.1	17.3
Cost Effectiveness, $/ton (calculated)	$ 10,910	$ 5,109	$ 15,770
ULNB $/ton (given)			
SCR			
Total Capital Requirement, $[1]	$ 4,450,581	$ 5,381,658	$ 3,497,247
Annual O&M Costs, $	$ 70,477	$ 78,061	$ 50,546
Capital Recovery Factor	0.0590	0.0590	0.0590
Capital Recovery Costs, $	$ 262,584	$ 317,518	$ 206,338
Total Annual Costs, $	$ 335,956	$ 398,529	$ 259,721
NO_x Reduction SCR	39.2	81.4	26.3
Cost Effectiveness, $/ton (calculated)	$ 8,562	$ 4,894	$ 9,865
SCR $/ton (given)			
SCR + ULNB			
Total Capital Requirement, $[1]	$ 7,276,581	$ 13,869,658	$ 6,746,247
Annual O&M Costs, $	$ 141,477	$ 290,061	$ 131,546
Capital Recovery Factor	0.0590	0.0590	0.0590
Capital Recovery Costs, $	$ 429,604	$ 818,855	$ 398,294
Total Annual Costs, $[1]	$ 571,081	$ 1,108,916	$ 529,839
NO_x Reduction ULNB+SCR	40.3	89.4	27.5
Cost Effectiveness, $/ton (Calculated)	$ 14,171	$ 12,404	$ 19,267
ULNB+SCR $/ton (given)			

As noted earlier, CHS omitted evaluation of simply adding SCR without the cost of new combustion controls. At 90% SCR control efficiency and with the correct CRF, the cost-effectiveness (in 2019$) of reducing NO_x emissions becomes < $5,000/ton for the Platformer Heater, <$9,000/ton for the Main Crude Heater, and < $10,000/ton for Boiler #9.

Factor 2: Time Necessary for Compliance

MDEQ: Although not specifically noted in the submitted four-factor analysis it is believed that any of the above controls could be implemented by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: The application of SCR to the candidate process heaters and boiler will result in the emissions of ammonia and additional fine particulate matter in the form of ammonium salts. The emission of ammonia results from incomplete utilization of all of the ammonia injected before the SCR catalyst. This unreacted ammonia will result in ammonia slip, and is either exhausted to the atmosphere as ammonia or combines with sulfur species in the flue gas to form ammonium salts.

The installation of an SCR system increases the pressure drop through the heater flue gas path requiring the installation of an induced draft fan on the Main Crude and Platformer Heaters. The induced draft fan and SCR system power requirements result in an increase in the emission rate of criteria pollutants (NOx, CO, GHGs, etc.) at the location where the power is generated. The spent catalyst is comprised of metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures.

ARD: These issues are common to these control technologies and can be minimized by proper operation and maintenance practices.

MDEQ: Energy Impacts: The energy impact of applying SCR to the candidate process heaters and boiler comes from the power required to drive the induced draft fan and operate the ammonia injection and storage equipment.

ARD: This is part of the economic analysis.

Factor 4: Remaining Useful Life

MDEQ: Although not specifically noted in the submitted four-factor analysis and because the costs for each retrofit were prohibitive, it is believed that the impact of retrofitting these older units could provide some emission reductions However future replacement of these units such as with the planned replacement of Boiler #9, are the best steps forward for this round of regional haze.

ARD: We agree that replacement of these unit, with appropriate emission controls, is the best approach. However, there is no federally-enforceable requirement for CHS to adopt this approach.

Step 5 – Select Reasonable Progress Control

SO_2

MDEQ: Montana determined that no additional emission reductions should be required and that the existing flare and flare gas recovery system have provided significant SO_2 reductions and the continued optimization of these relatively new systems provide opportunity for future SO_2 reductions.

NOx

MDEQ: Montana determined that ULNB and ULNB plus SCR are cost-prohibitive with a range of $13,000 to $39,000 per ton of emission reduction across the process heaters and Boiler #9. No additional NO_x control is required for the second planning period.

ARD: MDEQ has overestimated control costs and omitted review of the most-cost-effective control strategy—standalone SCR.

Conclusions & Recommendations

- We are seeing cost-effectiveness thresholds of \$5,000/ton in TX, \$7,000/ton in NM, and \$10,000/ton in CO and OR.
- At 90% SCR control efficiency and with the correct CRF, the cost-effectiveness (in 2019\$) of reducing NO_x emissions becomes:
    - < \$5,000/ton for the Platformer Heater. The annual average cost effectiveness of adding SCR would be acceptable in the context of the thresholds used by TX, NM, CO, and OR. Addition of SCR could reduce unit NO_x emissions by over 80 tons/year.
    - <\$9,000/ton for the Main Crude Heater. The annual average cost effectiveness of adding SCR would be acceptable in the context of the thresholds used by NM, CO, and OR. Addition of SCR could reduce unit NO_x emissions by almost 40 tons/year.
    - < \$10,000/ton for Boiler #9. The annual average cost effectiveness of adding SCR would be acceptable in the context of the thresholds used by NM, CO, and OR. Addition of SCR could reduce unit NO_x emissions by over 25 tons/year.
- Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.12 FH Stoltze Land & Lumber Co.

Summary of NPS Recommendations and Requests for FH Stoltze Land & Lumber Co.

NPS ARD review of the four-factor analysis conducted for F.H. Stoltze Land and Lumber Co. (Stoltze) finds that there are technically feasible and cost-effective opportunities available to further control NO_x emissions from the facility. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: \$5,000/ton in TX, \$7,000/ton in NM, and \$10,000/ton in CO and OR.

Our revised cost analysis estimates the annual average cost effectiveness of adding SNCR to reduce NO_x emissions at Stoltze would be acceptable in the context of the thresholds used by CO and OR and reduce NO_x emissions by 16 tons/year. This estimate assumes 22% control efficiency. If the SNCR could achieve 50% control efficiency the cost effectiveness would be around \$6,000/ton.

We recommend that MDEQ require the technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

F.H. Stoltze Land and Lumber Co. (Stoltze) owns and operates a sawmill facility located near Columbia Falls, Montana, 14 km south of Glacier National Park, a Class I area administered by the NPS.

MDEQ: The sawmill includes a biomass-fired boiler that supplies steam for lumber drying and for steam-powered electrical generation. The boiler was manufactured by Wellons Inc. in 2012 and is referred to as the Wellons boiler.

Stoltze RepBase and 2028 OTB/OTW Scenarios

MDEQ: Stoltze selected the two-year average of 2017-2018 as representative of baseline emissions. Montana concurred that this two-year period was reflective of recent normal operation. Stoltze was not asked to conduct an analysis on SO_2. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 31. MT Draft SIP Table 6-37 Stoltze RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	73.9	7.1	73.9	7.1

ARD: What were 2019 and 2020 emissions?

NO_x Evaluation

Step 1 – Identify All Available Technologies

MDEQ: The Wellons boiler was subject to a BACT analysis during the permit application process when it was permitted in 2012. The BACT analysis included consideration of combustion controls and add-on NO_x emissions controls.

The Wellons boiler is equipped with staged combustion flue gas recirculation and over-fire air. These NO_x control technologies are required by the Montana air quality permit for the facility.[22]

Additional control could be achieved by add-on emissions control technology as discussed below. The efficiency of the add-on controls would be reduced because of the low NO_x concentration emitted from the boiler. Because the Wellons boiler is already equipped with combustion controls, this cost-effectiveness analysis only considers add-on controls including:

Selective Catalytic Reduction
Selective Non-catalytic Reduction

SCR control technology works best for flue gas temperatures between 575°F and 750°F. SCR is typically installed upstream of the particulate control equipment where the temperature is high enough to support the process. When the combustion source is a biomass-fired boiler, the SCR must be placed downstream of the particulate control equipment for proper operation. At this point in the exhaust system, the flue gas

[22] https://deq.mt.gov/Portals/112/Air/AirQuality/Documents/ARMpermits/2934-01.pdf

temperature is lower than required for the SCR to operate effectively. Source tests of the Wellons boiler stack show an average stack exit temperature of 285ºF.

ARD: We agree with MDEQ.

Step 2 – Eliminate Technically Infeasible Options

MDEQ: The Wellons boiler underwent BACT analysis when it was permitted in 2012. At that time, Wellons stated they had never installed an SCR on a wood-fired boiler this small, and Wellons was not confident that the system could operate effectively as they have no operating experience. Stoltze considers this alternative technically infeasible and SCR is eliminated from any further consideration as a feasible control technology.

ARD: We disagree. Oregon has included this provision in its draft SIP:

> *If a new power purchase agreement is signed, within 180 days of notifying DEQ, Biomass One shall submit a complete application for installation of NO_x reduction technology that includes SCR on the North and South Boiler or demonstrates SCR is technically infeasible or presents other unacceptable energy or non-air quality impacts.*

The excerpt below is from the New Hampshire draft Regional Haze SIP:

> ***Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NO_x at the time of their initial permitting; hence, the NO_x limit was established as the LAER[23] based limit. The NO_x limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for SO_2 at the time of its initial permitting in 2010; hence, the SO_2 limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. SO_2/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the SO_2 BACT. Sorbent injection was installed for acid gas control but is not used to control SO_2 emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs SO_2/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for SO_2. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NO_x and SO_2. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.*

[23] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short-term limits for these two facilities are 0.060 lb/MMBtu.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: The Wellons boiler is currently equipped with combustion controls to minimize the formation of NO_x emissions. The permit limit for NO_x emissions is 0.26 pounds per million Btu (lb/MMBtu), which is equivalent to 18.2 pounds per hour (lb/hr). The analysis identified SNCR as the only feasible add-on NO_x control technology that could potentially be applied to the Wellons boiler. The estimated control efficiency for SNCR is 30%-50%. Because the Wellons boiler is equipped with NO_x reduction technology, the lower end of the efficiency range, 30%, is assumed. Based on the assumption of a 30% control efficiency, the NO_x emission rate could be reduced to 0.18 lb/MMBtu and 12.7 lb/hr.

ARD: Based on the data presented in Figure 1.1c in the CCM, we estimated that addition of SNCR could reduce NO_x emissions by 22%.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: The cost of compliance analysis was based on a spreadsheet developed by EPA to implement the June 2019 update of the SNCR chapter of the EPA Control Cost Manual.

ARD: The referenced workbook was revised in 2021 to correct an error that could lead to overestimation of operating costs.

MDEQ: The SNCR cost estimate spreadsheet is designed for use with coal-fired and oil- and natural gas-fired boilers. The spreadsheet was modified for use with the Wellons boiler by substituting wood fuel characteristics for coal characteristics. The fuel information for the wood/bark fuel is based on fuel analysis for samples collected during the most recent source test on the Wellons boiler.

The Stoltze sawmill cuts green lumber which is dried in lumber kilns. Steam to heat the for the kilns is supplied by the Wellons boiler which has a nominal rated capacity of 40,000 lb/hr and heat input up to 70 MMBtu/hr. Steam from the boiler is used to run a generator which produces 2.5 megawatts (MW) of power.

The steam heat output is converted to MW using the heat content of saturated steam (1,191 Btu/lb steam) and the following conversion:

> 40,000 lb steam/hr * 1,191 Btu/lb steam * 1 MMBtu/(1E6 Btu) = 47.64 MMBtu/hr heat output
> 47.64 MMBtu/hr ÷ 3.412 MW/MMBtu/hr = 13.96 MW
> Additional 2.5 MW Electrical Power
> NPHR = 70 MMBtu ÷ (13.96MW + 2.5MW) = 4.25 MMBtu/MW

The maximum potential inlet NO_x emissions to the SNCR are 0.26 lb/MMBtu as limited by the air quality permit. A removal efficiency of 30% is assumed, and the outlet NO_x emissions from the SNCR would be 0.182 lb/MMBtu.

ARD: We estimated 22% removal based upon CCM Figure 1.1c and estimated controlled emissions of 0.203 lb/mmBtu.

MDEQ: The estimated Normalized Stoichiometric Ratio (NSR) was obtained from the EPA Control Cost Manual for SNCR. Figure 1.8 of the control cost manual chapter on SNCR shows the lowest NO_x emission rate for which SNCR control would be applied is 0.40 lb/MMBtu. The corresponding NSR of 1.15 for 0.40 lb/MMBtu and 30% removal efficiency was used in the spreadsheet. For this application, it was assumed that the SNCR would use urea, and the reagent values for urea in the spreadsheet are the default values.

ARD: We applied CCM equation 1.17 to estimate the NSR for 22% control at 1.04.

MDEQ: The cost values are based on the 2018 Chemical Engineering Plant Cost Index (CEPCI) value of 603.1, based on the annual average.

ARD: We used the 2019 CEPCI = 607.5.

MDEQ: The spreadsheet default annual interest rate of 5.5% was used.

ARD: We used the current prime interest rate (3.25% in November 2021) as recommended by the CCM.

MDEQ: The fuel cost for the hog fuel was estimated to be \$2.05/MMBtu based on an assumed cost for handling the fuel of \$20 per ton and a fuel high heating value (HHV) of 9.76 MMBtu/ton. Ash disposal cost was not included because the spreadsheet excludes ash removal costs for non-coal fuels. The spreadsheet default costs for reagent, water and electricity were used in the analysis. The cost calculation results showed that the addition of SNCR to the Wellons boiler would have a cost effectiveness of \$8,092 per ton of NO_x removed, in 2018 dollars.

ARD: The cost-effectiveness is highly dependent upon the SNCR control efficiency. With the adjustments we made to CEPCI (higher) and interest rate (lower), at 22% control efficiency we estimate cost effectiveness = \$9,895/ton. However, if SNCR at Stoltze can achieve 50% efficiency, the cost-effectiveness becomes less than \$6,000/ton.

Factor 2: Time Necessary for Compliance

MDEQ: Stoltze estimated that SNCR would require approximately 24 months for design, permitting, financing, etc. through commissioning. Montana has concluded that any required controls could be installed by 2028.

ARD: This is exceptionally long for SNCR and should be documented/justified.

Factor 3: Energy and Environmental Impacts of Compliance

MDEQ: SNCR presents several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)2SO_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

ARD: SNCR is widely used and the problems cited by MDEQ can be minimized by proper operation and maintenance.

MDEQ: An SNCR system would have a very small energy penalty on the overall operation cost of the boiler. Costs for this energy expenditure are included in the discussion of Factor 1, cost of compliance.

ARD: Energy costs are included in the EPA SNCR workbook relied upon by MDEQ and ARD.

Factor 4: Remaining Useful Life

MDEQ: The Wellons boiler was manufactured in 2012 and installed at the Columbia Falls facility in 2013. For this four-factor analysis, it has been assumed that the boiler has a remaining useful life of 20 years based on Montana's guidance which stated that a 20-year planning horizon should be assumed for the purpose of the requested reasonable progress analysis. The only exception to this horizon is if there is a unit shutdown date identified that will cease operations before 20 years has expired.

Step 5 – Select Reasonable Progress Control/Final State Recommendations

MDEQ determined that SNCR is cost-prohibitive for the second planning period, noting that the Wellons boiler is relatively new with existing NO_x controls permitted under BACT in 2012. MDEQ determined that no additional NO_x control is required for the second planning period.

ARD: MDEQ should clearly state the criteria it used (e.g., $/ton) to make this determination. 2012 BACT could be obsolete.

Conclusions & Recommendations

- We are seeing cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The annual average cost effectiveness of adding SNCR at Stoltze would be acceptable in the context of the thresholds used by CO and OR and reduce NO_x emissions by 16 tons/year.
- Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.13 Sidney Sugars Inc.

Summary of NPS Recommendations and Requests for Sidney Sugars Inc.

NPS ARD review of the four-factor analysis conducted for Sidney Sugars finds that there are technically feasible and cost-effective opportunities available to further control NO_x emissions from the facility.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

Our review finds that the annual average cost effectiveness of adding SNCR or SCR to reduce NO_x emissions at Stoltze would be acceptable in the context of the thresholds used by all of the states referenced.

We recommend that MDEQ require the most effective of the technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

Sidney Sugars is located in Sidney, Montana, about 55 km northwest of Theodore Roosevelt National Park, administered by the NPS.

MDEQ: Sidney Sugars consists of four boilers that are each evaluated in this analysis. The four emitting units are identified as CE Boiler #1, CE Boiler #2 Union Boiler #3, and Union Boiler #4.

ARD: What is the heat input for each boiler? What are the annual average emission rates (lb/mmBtu) for SO_2 and NOx?

MDEQ: The Sidney Sugars facility is a season system that processes sugar beets using lignite coal supplied by the Savage Mine, which also supplies coal to MDU-Lewis and Clark Station. Section 4.3.7 discusses the MDU-Lewis and Clark Station and coal use from the Savage mine, including plans for ceasing operation by 2028. Sidney Sugars is a small purchaser of Savage Mine coal and the continued availability of lignite coal may change after MDU-Lewis and Clark ceases coal use. If lignite coal is no longer available, a likely scenario would be a conversion to natural gas; however, this would likely require installation of new natural gas-fired boilers, thereby invalidating any new NO_x control which may have been installed for controlling NO_x while burning coal.

ARD: What is the heating value, sulfur content, and ash content of the fuel?

Sidney Sugars RepBase and 2028 OTB/OTW Scenarios

MDEQ: Sidney Sugars selected the two-year average of 2017-2018 emissions for their representative baseline. Montana concurred that this two-year period was reflective of recent normal operation. Sidney Sugars also selected a future year 2028 OTB/OTW scenario, that was used to calculate the cost per ton of emission reduction achieved from applying controls.

Sidney Sugars chose to use the 2017-2018 representative baseline for the 2028 OTB/OTW scenario. Sidney Sugars was not asked to conduct an analysis for SO_2 reductions as their baseline emissions for SO_2 were relatively low and Montana determined that pursuing NO_x reductions represented a higher priority at this time. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 32. MT Draft SIP Table 6-38. Sidney Sugars RepBase and 2028 OTB/OTW Emissions

Baseline Period	Rep. Baseline NOx	Rep. Baseline SO_2	2028 OTB/OTW NOx	2028 OTB/OTW SO_2
2017-2018	224.0	61.7	224.0	61.7

ARD: What were the 2019 and 2020 emissions?

NO_x Evaluation

Step 1 – Identify All Available Technologies

MDEQ: Sidney Sugars used a reference document titled Amec Foster Wheeler Environmental & Infrastructure, Inc.; Final Four-factor Analysis for Regional Haze in the Northern Midwest Class I Areas, dated October 27, 2015, to perform the analysis for the four boilers.[24] The available Potential NO_x Control Options for Industrial, Commercial, and Institutional Boilers at Sugar Beet Manufacturing Facilities are summarized as follows. As this document specifically looked at Sugar Beet manufacturing facilities, Montana considers this a reasonable review of available technologies. The control performance efficiencies are also included.:

Table 33. MT Draft SIP Table 6-39. Sidney Sugars Available Control Technologies

Technology	Description	Applicability	Performance
Boiler Tuning/Optimization	Adjust air to fuel ratio	Potential control measure of all boilers	5-15% reduction in NOx
LNB	Low NO_x burners	Potential control measure for all boilers; dependent upon fuels burned, boiler use, and boiler configuration	40-50% reduction in NOx
ULNB	Ultra-low NO_x burners	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	45-85% reduction in NO_x
LNB+FGR	Low NO_x burners and flue gas recirculation	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	50-70% reduction in NO_x
LNB+OFA	Low NO_x burners and over-fired air	Potential control measure for all boilers; dependent on fuels burned, boiler use, and boiler configuration	40-60% reduction in NO_x
SCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst	Potential control measure for all boilers; dependent on flue gas temperature and boiler configuration	70-90% reduction in NO_x
SNCR	A reducing agent such as ammonia is introduced	Potential control measure for all boilers; dependent	10-70% reduction in NO_x

[24] https://www.ladco.org/wp-content/uploads/Documents/Reports/Regional_Haze/Round2/2015_LADCO-4-Factor-Analysis-Regional-Haze.pdf

	into the flue gas stream to form nitrogen gas	on flue gas temperature and boiler configuration	
RSCR	A reducing agent such as ammonia is introduced into the flue gas stream to form nitrogen gas in the presence of a catalyst and heat exchangers	Potential control measure for all boilers; dependent on boiler configuration	60-75% reduction in NO_x

Step 2 – Eliminate Technically Infeasible Options

MDEQ: Sidney Sugars provided the following table, eliminating those technologies as noted. Montana does not fully concur that each of the options as noted are technically eliminated. Where stack temperatures have been noted as too low, add on reheat options allow options to making these technologies work. The costs may become excessive and may be result in those options being eliminated for not being cost effective but not because of they are technically infeasible.

Table 34. MT Draft SIP Table 6-40. Sidney Sugars Control Options Cost Effectiveness

Control Option	Specific Design Parameters Identified	Cost Effectiveness (2015 $/ton)	Factors Affecting Cost	Potential Applicability to Specific Boilers
Boiler Tuning/Optimization	None	Low	Engineering and contractor costs	All Boilers
LNB	None	$450-$3,700	Equipment, installation, and engineering	All Boilers
ULNB	None	$650-$2,200	Equipment, installation, and engineering	All Boilers
LNB+FGR	None	$1,200-$4,300	Equipment, installation, construction, and engineering	Union Boilers only
LNB+OFA	None	$700-$3,700	Equipment, installation, construction, and engineering	All Boilers
LNB+SNCR	Urea injection system	$1,700-$4,500	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable- Infeasible, stack temps too low
ULNB+SCR	Ammonia injection system	$2,900-$5,100	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable- Infeasible, stack temps too low

SCR	Ammonia injection system	$2,600-$17,000	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low
SNCR	Urea injection system	$1,500-$4,400	Equipment, installation, engineering, energy use, waste removal, and reduction agent	Not Applicable-Infeasible, stack temps too low
RSCR	Ammonia injection system	$1,800-$5,300	Equipment, installation, engineering, energy use, waste removal, reduction agent, and catalyst	Not Applicable-Infeasible, stack temps too low

ARD: Stack temperature would not affect the feasibility of SNCR. North Dakota has determined that Tail-End SCR is technically-feasible on lignite-fired boilers (except cyclone boilers). We advise that Tail End-SCR is likely technically feasible on all lignite-fired boilers, including those at Sydney Sugars.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

MDEQ: Under Step 1, - Identify All Available Technologies, Sidney Sugars indicated the approximate control efficiencies possible with each alternative. All control technologies listed in Table 6-40 remain and are evaluated through the remainder of this analysis.

ARD: We assume that MDEQ is referring to the combustion control options and excluding any option including SCR or SNCR.

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

MDEQ: Based on the above cost-range estimates, Sidney Sugars has indicated that the only cost-effective controls would be for combustion modifications. However, Montana has not arrived at the same conclusion. Each of the alternatives listed above may be feasible, given some additional reheating scenarios that could be implemented and were not evaluated by Sidney Sugars.

ARD: It appears that each of the potential control technologies could be economically-feasible.

Factor 2: Time Necessary for Compliance

MDEQ: Sidney Sugars provided information that allows Montana to conclude that any required controls could be implemented by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: Non-air environmental impacts include solid, liquid, and/or hazardous waste generation and deposition of atmospheric pollutants on land or water.

ARD: These impacts are not unique to this site.

MDEQ: Combustion modifications would have significant negative impacts on energy use. Boiler tuning, LNB/ULNBs, OFA, and FGR would reduce the efficiency of a boiler as the air to fuel ratio increases and temperature decreases. This increases fuel usage and, as a result, costs. OFA and FGR systems increase energy use in the form of fans and compressors.

ARD: These impacts should be included in the economic analysis.

Factor 4: Remaining Useful Life

MDEQ: Life expectancy for the Sidney Sugars CE Boilers and Union Boilers is estimated at between 10 and 30 years or more. Since Sidney Sugars did not provide any specifics Montana assumed that all boilers have a remaining useful life of at least 20 years.

ARD: In the absence of federally-enforceable shut-down conditions, we assumed 20 years for SNCR and 25 years for SCR according to EPA's Control Cost Manual (CCM)

Step 5 – Select Reasonable Progress Control

MDEQ: There remains a potential option to replace the CE Boilers (i.e., coal fired boilers) with natural gas fired boilers. As it is unclear whether the CE Boilers will continue to have a supply of lignite coal from the Savage Mine, Montana has determined to not require controls on the CE Boilers given that the costs of those controls would likely be stranded. Additionally, any retrofit controls that might be required for combusting coal could also be stranded if Sidney Sugars were to move to natural gas-fired boilers. Therefore, no NO_x controls are required for the second planning period. However, if the Savage Mine remains operational or if Sidney Sugars outsources to another coal mine, NO_x controls may be required in a future planning period.

ARD: How likely is it that costs of any controls would be stranded? Is MDEQ referring to "stranded costs" or "sunk costs"? Over what time period would these costs be amortized? Would that involve a federally enforceable shut-down condition? Considering the uncertainty regarding the future fuel source for these boilers, installation of SNCR would present a relatively low capital cost option. We recommend that at a minimum this facility should be flagged for re-analysis during the mid-term review.

Conclusions & Recommendations

We are seeing cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The annual average cost effectiveness of adding SNCR or SCR at Sidney Sugars would be acceptable in the context of the thresholds used by TX, NM, CO, and OR.

Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.14 Phillips 66 Co. - Billings Refinery

Summary of NPS Recommendations and Requests for Phillips 66 Co. - Billings Refinery

NPS ARD review of the four-factor analysis conducted for Phillips 66 (P66) finds that there are technically feasible and cost-effective opportunities available to further control NO_x emissions from the facility.

Although MT has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

Our revised cost analysis estimates that the annual average cost effectiveness of adding SCR at P66 would be acceptable in the context of the thresholds used by all of the states listed. Addition of SCR could reduce facility NO_x emissions by over 110 tons/year. In this situation, SNCR is less cost effective and would not meet the cost thresholds established by other states.

We recommend that MDEQ require technically feasible and cost-effective controls identified through four-factor analysis. Doing so would reduce haze causing emissions and advance the incremental improvement of visibility at Glacier, Yellowstone, and Theodore Roosevelt National Parks as well as other Class I areas in the region.

Facility Characteristics

Phillips 66 (P66) is an integrated petroleum refinery in Billings, MT, 145 km northeast of Yellowstone National Park a Class I area administered by the NPS.

MDEQ: P66 includes crude oil distillation, delayed coking, fluid catalytic cracking, hydrotreating, alkylation, and other associated petroleum refining processing units and auxiliary operations. Associated with P66 are the adjacent Jupiter Sulphur LLC sulfur recovery operations (Jupiter Plant), which recover sulfur from the sour-acid gas streams generated at P66.

Refineries contain many small emitting units that, in aggregate, contribute to emissions of SO2 and/or NO_x at the facility. Because of this, Montana determined that it was impractical to perform a four-factor analysis on each individual emitting unit. Montana and P66 agreed on a ranking of the highest emitting units for both NO_x and SO_2 that could be evaluated in the four-factor analysis. Doing so provided the information necessary to determine opportunities for emissions reductions at the facility. P66's NO_x emissions are significantly larger than SO_2, so Montana agreed that the greatest effort should be put into identifying opportunities for NO_x reductions at P66.

ARD: What is the refinery's daily and annual throughput. Please provide a plantwide emissions inventory.

MDEQ: This analysis focuses on emissions from Boiler #1 and Boiler #2 because these two units are responsible for approximately 22% of the NO_x emissions from the plant (based on 2018 emissions). Future planning periods may evaluate other emitting units; however, evaluating the highest existing emitting units in this planning period provides a reasonable approach to identifying possible emission reduction opportunities.

P66 RepBase and 2028 OTB/OTW Scenarios

MDEQ: P66 selected the two-year average of 2017-2018 as representative of baseline emissions. Montana concurred that this two-year period was reflective of recent normal operation. P66 also selected a future year 2028 OTB/OTW scenario used to calculate the cost per ton of emission reduction achieved from applying controls. P66 chose to use the 2017-2018 representative baseline for the 2028 OTB/OTW scenario. Representative baseline and 2028 OTB/OTW emissions are as follows:

Table 35. MT Draft SIP Table 6-41. P66 RepBase and 2028 OTB/OTW Emissions

Baseline Period	**Rep. Baseline NOx**	**Rep. Baseline SO_2**	**2028 OTB/OTW NOx**	**2028 OTB/OTW SO_2**
2017-2018	563.5	100.7	563.5	100.7

ARD: What were 2019 & 2020 emissions? Please provide a refinery emissions inventory.

SO_2 Evaluation[25]

MDEQ: All combustion devices fired with refinery fuel gas at the P66 Refinery are subject to and comply with Standards of Performance for Petroleum Refineries (NSPS, 40 CFR 60, Subpart J and Ja). which includes a hydrogen sulfide content limit of 162 ppmv or less in refinery fuel gas on a 3-hour rolling average basis. In addition, other standards apply from terminated EPA Consent Decree requirements (that have largely been incorporated in permit conditions), state SIP requirements, and other NSPS limits to further control SO_2 emissions from the fluidized catalytic cracking unit (FCCU), among other units.

ARD: What is the H_2S content of the refinery gas? How is it achieved?

MDEQ: For the 2017-2018 baseline summary, P66 averaged 100.7 tons per year of SO_2 emissions over 38 emissions sources/points that have the potential to emit SO_2. While those emissions are not evenly distributed over those sources, many of the SO_2 sources are small boilers or heaters subject to NSPS Subpart J/Ja or other requirements or are larger well-controlled SO_2 sources (the FCCU or sulfur recovery units, for example). Given the number of sources and relatively small emissions per source, continued compliance with the above-mentioned standards and permit limits, should continue to keep SO_2 emissions at or near the current levels.

NO_x Evaluation

Step 1 – Identify All Available Technologies

MDEQ: The recently-terminated EPA Consent Decree included significant emissions reductions for units across the refinery. These reductions included a NO_x Control Plan for heaters and boilers (implementing NO_x controls on at least 30% of the heater and boiler capacity greater than 40 million British Thermal Units per hour, MMBtu/hr) as well as catalyst additive demonstrations at the FCCU (with an associated NO_x emission limit).

The NO_x analysis focused on Boilers #1 and #2 as these two units are responsible for approximately 23% of the NO_x emissions from the plant (based on the 2017-2018 baseline emissions). Twenty-one other NO_x sources (with greater than five tons/year emissions) split the other 77% of the NO_x emissions, with three of those sources being grouped sources (gasoline engines, for example, or units with multiple fuel types in the inventory). Many of those twenty-one sources already have seen recent emissions control upgrades under the Consent Decree. The identified applicable NO_x control technologies are described below and include:

Ultra-Low NO_x Burners with Flue Gas Recirculation
Selective Non-Catalytic Reduction
Selective Catalytic Reduction.

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[25] SO_2 emissions from P66 are relatively low, with NOx emissions being five times higher than SO_2. Therefore, Montana requested that P66 look specifically at NOx controls for this planning period. However, a limited analysis on SO_2 reductions was conducted.

The NO_x basis ("uncontrolled emissions") for Boilers #1 and #2 is the 2019 annual emission inventory factor of 0.27451 lb/MMBtu.

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

MDEQ: For SNCR, urea was assumed as the reagent in the P66 SNCR cost analysis. An average reduction of 58.5% was assumed using EPA's SNCR Cost Calculation Spreadsheet, using the "retrofit factor" of 1 - average retrofit.

ARD: SNCR control efficiency is related to uncontrolled NO_x emissions. We applied the relationship in Figure 1.1c. in EPA's Control Cost Manual (CCM) and estimated 22.4% NO_x control efficiency for these boilers.

SELECTIVE CATALYTIC REDUCTION (SCR)

MDEQ: The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/MMBtu. Based on that limitation, the proposed reduction associated with SCR for Boilers #1 and #2 is 85.4% based on current engineering mass balance/emissions factor of 0.2745 lb/MMBtu.

ARD: We found over 1,300 boilers in EPA's Clean Air Markets Database < 0.04 lb/mmBtu. The controlled SCR emissions rates used in MDEQ's Exxon analysis were based on a 95% control efficiency. We assumed 90% control in our analysis for P66.

MDEQ: Ammonia is the most commonly used reagent, so it was used in the reagent calculations for Boilers #1 and #2. The costs provided for SCR in the four-factor analysis are calculated using EPA's SCR Cost Calculation Spreadsheet and also use the "retrofit factor" of 1 - average retrofit.

Step 2 – Eliminate Technically Infeasible Options

MDEQ: Because of the intrinsic nature of both controls (often used in conjunction), they are generally installed in new boilers. While retrofits have occurred (and did, in specific instances during the EPA Refinery Consent Decree NO_x reductions), they generally occurred on smaller, newer, and a low number of burners. Based on corporate information, practices, and similar unit Consent Decree-required retrofits, P66 believes this type of a retrofit for Boilers #1 and #2 would be a difficult and expensive effort that would likely result in complete demolition and replacement of both boilers, at an estimated cost of $40 million for both ($20 million per boiler).

To annualize that cost and provide a cost per ton value for new RFG-(Refinery Fuel Gas) fired boilers equipped with ULNB and FGR, a NO_x limit of 0.03 lb/MMBtu was used. This assumes the new boilers are of the same general size/capacity as Boilers #1 and #2 and general utilization. The 0.03 lb/MMBtu NO_x limit comes from the recent retrofit of Boiler-5 and Boiler-6 at the P66 Billings Refinery. The $40 million total cost includes capital expenditures and demolition for both boilers but does not include annual maintenance costs associated with UNLB/FGR.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

ARD: We revised the MDEQ table to reflect our estimates of SNCR and SCR efficiencies as shown below.

Table 36. ARD Revised MT Draft SIP Table 6-42. P66 Potential Control Options

Source	Potential Control Option	Estimated Control Efficiency (%)
Boiler #1 and Boiler #2 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	22.4
	SCR	89.1
	Replacement with new boiler equipped with ULNB and FGR	89.0

Step 4 – Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

ARD: We have revised MDEQ's Table 4-46 (below) to reflect our application of EPA's CCM workbooks with the following modifications to P66's data inputs:

Interest rate = 3.25% (November 2021 prime)

Chemical Engineering Plant Cost Index (CEPCI) = 607.5 for 2019$

SNCR control efficiency is based upon CCM Figure 1.1c.

SNCR Normalized Stoichiometric Ration (NSR) is based upon CCM Eqn. 1,17.

SCR outlet emissions 0.03 lb/mmBtu based upon 89% control efficiency and over 1300 boilers in EPA's Clean Air Markets Database < 0.04 lb/mmBtu.

SCR life = 25 years (CCM default for industrial applications)

Table 37. ARD Revised MT Draft SIP Table 6-43. Estimated Costs of NO_x Control Options for P66, ranked by Control

Source	Potential Control Option	Potential Emission Reduction (tons/year)	Total Annual Cost (in 2019 dollars)	Cost Effectiveness ($/ton)
Boiler#1 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	15	$170,998	$11,690
	SCR	58	$283,552	$4,884
	Replacement with new boiler equipped with ULNB and FGR	58	$1,053,634	$18,166
Boiler #2 (120 MMBtu/hr, refinery fuel gas fired)	SNCR	15	$170,871	$11,726
	SCR	58	$283,457	$4,901
	Replacement with new boiler equipped with ULNB and FGR	58	$1,053,634	$18,166

Factor 2: Time Necessary for Compliance

ARD: MDEQ concluded that any controls could be operational by 2028.

Factor 3: Energy and Non-air Quality Environmental Impacts of Compliance

MDEQ: In general, the use of combustion controls for reducing NO_x formation can in turn cause an increase in CO emissions. SCR and SNCR both present several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2S0_4$. The ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

ARD: These issues are common to these control technologies and can be minimized by proper operation and maintenance practices.

MDEQ: In addition, SCR would require disposal or recycling of catalyst materials, which may require handling in a specific landfill for hazardous waste.

ARD: These issues are common to this control technology. Many catalyst vendors provide catalyst disposal/regeneration services.

Factor 4: Remaining Useful Life

ARD: In the absence of federally enforceable limits on the life of these boilers, we assumed that they would operate for the 25-year SCR life.

Step 5 – Select Reasonable Progress Control

MDEQ: Montana concurs with the P66 prepared and submitted four-factor analysis that additional controls for NO_x are not warranted for this planning period. No additional NO_x control is required for the second planning period. Future planning periods may revisit the need for emission reductions.

ARD: MDEQ has not made its decision criteria publicly available. MDEQ did not identify any cost-effectiveness thresholds and determined that no additional NO_x control is required for the second planning period.

Conclusions & Recommendations

- We are seeing cost-effectiveness thresholds of $5,000/ton in TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The annual average cost effectiveness of adding SNCR at P66 would not be acceptable in the context of the thresholds used by CO, NM, and OR.
- The annual average cost effectiveness of adding SCR at P66 would be acceptable in the context of the thresholds used by TX, NM, CO, and OR. Addition of SCR could reduce facility NO_x emissions by over 110 tons/year.
- Of the four statutory factors, only the Cost of Compliance is an issue for the technically-feasible controls. MDEQ should require application of cost-effective, technically-feasible controls.

2.2.15 Northern Border Pipeline Compressor Station 3

Summary of NPS Recommendations and Requests for Northern Border Pipeline Compressor Station 3

Final NPS ARD feedback on the Northern Border Pipeline Company's (NBPL) four-factor analysis of NO_x controls for their Compressor Station No. 3 is provided below. In summary, we find that SCR may be cost effective even under reduced operating scenarios. Our revised cost-effectiveness estimates are significantly lower than those estimated by NBPL and reported in the draft SIP.

Source Background:

The NBPL Compressor Station #3 facility consists of a 40,350 HP Cooper Rolls turbine which is currently equipped with lean premixed combustion (DLE). The permitted NO_x BACT limit is 51.5 lb/hr (based on a manufacturer's guaranteed emission factor of 40 ppmvd). The permit allows up to 750 hours of firing per year without the DLE in operation at 78.0 lb/hr NOx.

NBPL Cost Effectiveness Estimate:

Because the source is already equipped with DLE, NBPL evaluated SCR only. NBPL estimated the cost effectiveness of SCR for the Cooper Rolls turbine to be **$37,750/ton NO_x removed.** This is an excessively high estimate. We found several issues/errors/technical deficiencies in NBPL's analysis that contribute to the overestimate, which are outlined below. We provided a list of these technical deficiencies to Montana in November 2020; however, these deficiencies have not been corrected. Montana accepted the NBPL cost analysis and incorporated it into the 2021 draft SIP.

Technical Issues with NBPL's Cost Analysis:

Section 6.2.27 of the draft SIP as well as NBPL's July 11, 2019 four-factor analysis submittal outline the data and assumptions used in NBPL's analysis. We identified the following issues with NBPL's cost analysis:

Cost Calculation Methods

Although they cite the Control Cost Manual (CCM) as the basis for many of their estimates, the NBPL analysis did not utilize the methodology presented in the current 7th edition CCM chapter on SCR. In many cases, is not clear what cost methods NBPL used or what section of the CCM they are citing, but deviations from the 7th edition CCM SCR methods do not appear to be based on source-specific information such as vendor quotes. The NBPL cost analysis should be revised using the most recent SCR chapter in the CCM. Our revised estimates are based on the 7th edition CCM methods for SCR.

Estimated Uncontrolled NO_x Emissions and Turbine Derating Assumptions

NBPL's analysis calculates estimated average uncontrolled NO_x emissions based on assumptions that derate the both the turbine's output and heat input. The net effect is a reduction in the calculated uncontrolled NO_x emission rate and thus the "tons of NO_x removed."

For example, the NBPL analysis assumed an "average operating load for future operations of 24,000 hp" which it claims is 63% of the rated capacity. (We note that this appears to be incorrect according to the source's Title Five permit, which lists the maximum rated capacity of the turbine as 40,350 HP.) NBPL notes that this operating load estimate is based on 18 months of operating data. NBPL then uses the 24,000 HP average operating load assumption with the permit heat rate (8,000 Btu/hp-hr) to reduce the turbine's rated heat input to 192 MMBtu/hr. (According to the Title Five permit, the maximum heat input for the turbine is 315 MMBtu/hr.)

NBPL then uses the derated heat input value along with 4,500 hours/year assumed average annual operating hours and the source compliance testing NO_x emission rate of 0.117 lb/MMBtu to calculate annual emissions. The resulting uncontrolled NO_x emission used in the NBPL cost analysis is 50.5 tons/year NOx.

There are several issues with NBPL's emission calculation approach:

- The 7th edition CCM cost methods use the heat input (Qb) to size the reactor and calculate total capital investment. As noted in the draft SIP and four-factor analysis, there is significant variation in annual operating loads, but in some years the facility operates for a significant portion of the year. The SCR system should be designed to accommodate all potential operating conditions, including maximum loads. Accordingly, adjusting fuel throughput, not the heat input, in the 7th edition CCM method is a better way to address a range of operating conditions.
- It may not be appropriate or representative to use a single cost estimate based on average emissions for a source with significant variation in annual operating hours, loads and emissions, particularly if the source operated at levels that are significantly higher than the average in recent years. Instead, it may be more informative to estimate a range of cost-effectiveness values based on a range of potential operating conditions. If the range of estimated costs are all below acceptable

cost-effectiveness thresholds, then it is more likely that the control is cost-effective. For this reason, our analysis considered a range of cost-effectiveness estimates based on a range of operating scenarios.

We question an emission estimation approach that uses operational averages to derate the turbine and then calculate annual emissions. What operational conditions are reflected in the compliance testing data used to establish the 0.117 lb/MMBtu NOx emission rate? This information was not provided in the four-factor analysis or the draft SIP. We recommend that it is more appropriate to estimate emissions in the CCM workbook by using the compliance testing emission rate and adjusting fuel throughput to reflect reduced loads and we used this approach in our analysis.

NBPL's analysis states that the uncontrolled NOx emission rate is based on 18 months of operational data but did not provide this data in their four-factor analysis. This is not an adequate record to establish operational averages, particularly for a source with significant variation in annual operating hours. Additional operational information for this source should be included in the four-factor analysis and draft SIP. The 2021 EPA clarification memorandum recommends use of the most-recent five years (2016 – 2020) of operational data.

The analysis assumed an uncontrolled NOx rate of 50.5 tons/year, based on both a reduced load/heat input and reduced annual operating hours to determine that SCR is not cost effective, but this is not an enforceable requirement. The turbine is permitted to emit up to 235.5 tons/year of NOx. Please note that the 2021 EPA clarification memorandum states that:

> *". . . in some cases states may have projected significantly lower total emissions due to unenforceable utilization or production assumptions and those projections are dispositive of the four-factor analysis. For example, a state that rejected new controls solely based on cost effectiveness values that were higher due to low utilization assumptions. In this circumstance, an emission limit that requires compliance with only an emission rate may not be able to reasonably ensure that the source's future emissions will be consistent with the assumptions relied upon for the reasonable progress determination."*

If a single average of operational conditions is used to dismiss a control, those operational conditions should be reflected in an enforceable condition.

Assumed Control Efficiency:

NBPL assumed SCR would achieve a 75% NO_x reduction, which is low. The NPS analysis assumes a 90.6% reduction, which reflects achieved control (on a ppmvd basis) from SCR installation on similar compressor stations (see NPS ARD workbooks).

Sales and Property Tax:

NBPL included a sales tax estimate of $130,050 and an annual property tax of $75,309. We understand sales tax is not applied to air pollution control projects in Montana and that they are exempt from property tax. Please clarify if this understanding is incorrect. (Note, for this reason, the new CCM SCR chapter does not include sales or property tax in cost estimates.)

Labor Costs:

All labor costs seem high relative to the 7th edition CCM cost calculation methods (see NPS ARD workbooks).

Catalyst Costs:

Annual Catalyst maintenance and replacement costs seem excessively high relative to the 7th edition CCM cost calculation methods (see NPS ARD workbooks).

Indirect Annual Costs:

All indirect annual costs, including administrative costs seem high (see NPS ARD CCM workbook).

Reagent Stoichiometric Ratio:

The NH4 stoichiometric ratio seems high. (Note, the default assumption in the CCM is 1.05.)

Capital Recovery Factor:

NBPL assumed a 5.25% interest rate and a 20-year equipment life. Please note, the current bank prime rate is 3.25%. Our revised cost estimates use the bank prime rate and a 25-year equipment life (as recommended by the CCM).

Reagent Costs:

Reagent costs seem high. NBPL assumed a reagent cost of $550/ton. Please note, using the U.S. Geological Survey, Minerals Commodity Summaries referenced in the CCM, the current (2019) price of NH3 is $230/ton (or $0.25/gal for 29% aqueous solution—See NPS cost workbooks).

NPS ARD Cost Effectiveness Estimate:

Given the technical deficiencies in NBPL's (and Montana's) analysis, we reassessed the SCR cost effectiveness using EPA's most recent guidance in the CCM, Chapter 2, Selective Catalytic Reduction (June 2019). For the reasons stated above, we estimated the costs under a range of operating scenarios. The NPS revised estimates are significantly lower than NPBL's, even when accounting for reduced load/reduced operating hours. Our revised cost effectiveness estimates for the various operating scenarios are as follows:

1. <u>Full load PTE scenario</u>: This scenario used the Title Five permitted NO_x emission limit for the turbine of 51.5 lb/hr (with DLE operation) and fuel throughput that reflects 8760 hours of operation. (Note, this results in an annual uncontrolled NO_x emission estimate that is slightly lower than the permitted annual limit because the Title Five permit allows the source to operate without DLE up to 750 hrs/yr at 78 lb/hr.) This scenario represents a lower bound for the cost estimate range.
    a. Estimated uncontrolled NO_x: 226 tons/year
    b. Estimated tons of NO_x removed: 204 tons/year
    c. Estimated cost-effectiveness: **$3,027/ton**

2. <u>2017 Annual Operating Hours Scenario</u>: This scenario used the compliance testing data NO_x emission rate for the turbine of 0.117 lb/MMBtu. The annual fuel throughput was ratioed to result in 6,835 hours of operation, the 2017 operating hours reported in the draft SIP and NBPL four-factor analysis. Given the concerns with NBPL's emission calculation methods, we recommend that this may be a more appropriate way to estimate annual emissions.
    a. Estimated uncontrolled NO_x: 126 tons/year
    b. Estimated tons of NO_x removed: 114 tons/year

c. Estimated cost-effectiveness: **$5,140/ton**

3. <u>2017 NEI Emissions Scenario</u>: This scenario used the compliance testing data NO_x emission rate for the turbine of 0.117 lb/MMBtu. The fuel throughput was ratioed to result in 88 tons/year uncontrolled NO_x emissions, the annual emissions reported in the 2017 NEI. This resulted in an estimated 4788 hours of annual operation. (Again, we note that we have concerns with NBPL's annual emission estimation methods. However, this scenario provides a lower estimate of annual operating hours to address a range of operating scenarios.)
   a. Estimated uncontrolled NO_x: 88 tons/year
   b. Estimated tons of NO_x removed: 80 tons/year
   c. Estimated cost-effectiveness: **$6,987/ton**

NPS Conclusions & Recommendations For NBPL Compressor Station No. 3

The NPS estimates are within the range of cost effectiveness thresholds used by other states in this round of regional haze planning, and we recommend that Montana consider SCR for this source. If MDEQ intends to defer additional reasonable controls for the NBPL compressor station #3 due to the reduced load/reduced operating hours scenario, we request MDEQ address whether NBPL be required to take operational permit limitations to reflect these assumptions.

2.3 Oil & Gas Area Source Recommendations

2.3.1 NPS Conclusions/Response for Oil and Gas Sources

Emissions from oil and gas sources in the Williston Basin (which includes portions of Montana as well as North and South Dakota) are significant and are impacting haze levels in Theodore Roosevelt National Park. Based on the final future year oil and gas inventories developed by the Western Regional Air Partnership (WRAP) Oil and Gas workgroup, the Williston Basin has the highest NO_x emissions of any oil and gas basin within the WRAP region.[26]

We recommend that NO_x emission reductions from upstream oil and gas area sources across the *entire* Williston Basin, including sources on the Montana side, will be necessary to improve visibility in Theodore Roosevelt National Park. As described in greater detail below, we request that Montana consider state-wide requirements to limit NO_x emissions from engines in the SIP.

Montana did not explicitly address upstream oil and gas area sources in the long-term strategy for regional haze. However, an extensive discussion of oil and gas development, production trends and associated emissions was included in Section 5.3. This section compared the "varying degree of oil and gas production between Montana and North Dakota" noting that in 2019, "oil production was nearly 10

[26] Final WRAP oil and gas inventories include the "Continuation of Historical Trends" projection as well as the Future Year Lower Scenario and Future Year Higher Scenario Spreadsheets. Final reports and spreadsheets for each future year inventory are available on the WRAP website at: https://www.wrapair2.org/ogwg.aspx. Estimates/comparisons drawn do not include the Texas side of the Permian Basin. Emissions from the Texas and New Mexico side of the Permian Basin combined likely rival those in the Williston Basin. Nonetheless, NOx emissions from upstream oil and gas sources near Theodore Roosevelt NP are substantial.

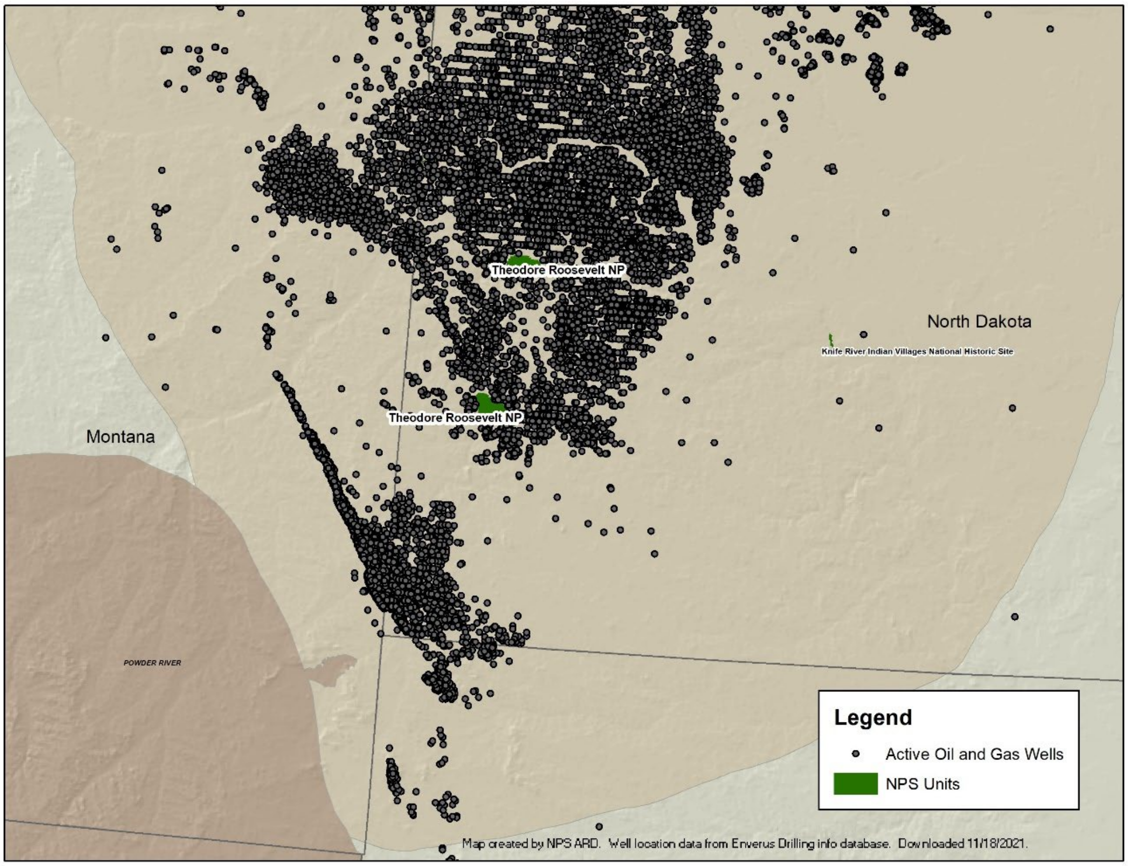
times higher and total gas production was 18 times higher" in North Dakota than in Montana. Based on this, the draft SIP infers that Montana oil and gas sources were not considered in the long-term strategy because oil and gas sources in North Dakota are more significant than sources in Montana. While we agree that oil and gas development is far greater in the North Dakota portion of the Williston Basin, when selecting sources and developing the long-term strategy, states should focus on their in-state contributions to impairment. EPA emphasizes this in Section 2.1 of the 2021 Clarification Memorandum:

> *"In applying a source selection methodology, states should focus on the in-state contribution to visibility impairment and not decline to select sources based on the fact that there are larger out-of-state contributors."*

As of December 1, 2021, there were 3,616 active, drilled or permitted wells within the Montana portion of the Williston Basin (out of 26,147 basin-wide).[27] As shown in Figure 7 below, the oil and gas development within the Williston Basin surrounds Theodore Roosevelt NP. Additionally, there are 1,221 active oil and gas wells due east of Glacier National Park in the Montana Thrust Belt region.[28]

[27] Source: Enverus DrillingInfo database, accessed 12/1/2021. See https://www.enverus.com/about-enverus/.
[28] Source: Enverus DrillingInfo database, accessed 12/1/2021. For additional information about the DrillingInfo database see: https://www.enverus.com/about-enverus/

Figure 7: Active Oil and Gas Well Surface Locations in the Williston Basin Near Theodore Roosevelt NP.



2.3.2 Engine Rules—NO_x Reduction Opportunity

The significant cumulative emissions from the upstream oil and gas source sector combined with the limited emissions footprint from any single wellsite points to the need for source category rules such as statewide engine rules. Many states now implement state or region-wide requirements to limit NO_x emissions from area source engines. We encourage Montana to consider similar rules and provide several examples here. Below is a summary of the best examples of statewide NO_x limits for NG-fired <u>lean-burn</u> engines:

- 0.5 g/hp-hr
  - TX requires this limit for all engines > 50 HP in their ozone nonattainment areas and a 33-county region.
  - PA requires this limit for all new and existing (permitted between 2013-2018) lean-burn engines > 500 HP
- 0.3 g/hp-hr
  - PA requires this limit for all new lean-burn engines > 2,370 HP
  - NM has permitted large (5,000 HP) engines at this limit
- 0.15 g/hp-hr (approximate conversion – limit is expressed as 11 ppmvd where 1 g/bhp-hr = approximately 73 ppmv for lean burn engines)

- CA's South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District require this for all engines > 50 HP. These were phased-in requirements. It is assumed that post combustion control is necessary to achieve these limits. Furthermore, the SCAQMD prioritizes engine replacement with electric motors.
- This limit is higher for engines used for gas compression in the SJVAPCD (65 ppmv or 0.89 g/hp-hr).

The options for retrofit or add-on controls that have the most significant emission reduction potential for engines include SCR and Low Emissions Combustion (LEC). The CSAPR TSD Assessment on Non-EGU NO_x Emission Controls[29] provides a good discussion of these control technologies and associated costs for lean-burn RICE. For example, regarding SCR installation on lean-burn engines, the EPA developed linear regression equations for capital and annual costs based on engine HP (2001–2003$). The EPA relied on information in a 2012 OTC document (Technical Information Oil and Gas Sector Significant Stationary Sources of NO_x Emissions) and a 2003 cost analysis completed by the CA South Coast Air Quality Management District in support of Rule 4702 when developing these linear regressions. NO_x reductions of approximately 90% or greater are achievable. EPA developed similar regression equations to estimate the costs of LEC retrofits.

Below is a summary of the best examples of statewide NO_x limits for NG-fired <u>rich-burn</u> engines:

0.20 g/hp-hr with the application of NSCR (a.k.a. 3-way catalyst)

- PA requires this limit for all rich-burn engines > 500 HP. PA also has a 0.25 g/hp-hr limit for all existing and new rich burn engines > 100 HP and ≤ 500 HP

0.16 g/hp-hr

- This limit is applicable in CA's South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District (see note below)

Please note, the CA and TX limits described above apply to rich and lean-burn engines alike (for rich burn engines, the 11 ppmvd limit in CA is approximately 0.16 g/hp-hr). It is anticipated that these limits will be achieved with NSCR. Colorado currently requires installation on NSCR on all rich-burn engines and recently approved a proposal that established NO_x limits for rich-burn engines of 0.8 g/hp-hr on existing engines (in service on or before November 14, 2020) and 0.5 g/hp-hr for new engines (in service, modified, or relocated after November 14, 2020).

We recommend that Montana consider engine rules similar to those implemented in Pennsylvania, Texas or California to reduce NO_x emissions from engines associated with upstream oil and gas operations.

2.3.3 NPS Oil and Gas Special Study

Data from an intensive study at Theodore Roosevelt National Park in 2013 and 2014 demonstrated that emissions from oil and gas activities are impacting ambient concentrations of nitrogen oxides, black

[29]EPA, Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Docket ID No. EPA-HQ-OAR-2015-0500; Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD U.S. Environmental Protection Agency Office of Air and Radiation, August 2016.

carbon and VOCs in the region (Prenni et al., Atmospheric Chemistry and Physics, 16, 1401–1416, 2016). Wintertime haze episodes were observed during this same study at the North Unit of Theodore Roosevelt National Park. (Evanoski-Cole et al., Atmospheric Environment, 156, 77-87, 2017). Haze episodes were associated with periods of stagnation and were dominated by emissions from the Bakken region. Formation of ammonium nitrate, the dominant haze component, was most sensitive to nitric acid concentrations during early spring, suggesting capacity for further ammonium nitrate formation if nitrogen oxide emissions increase.

Bakken oil and gas activities have also led to an increase in regional fine soil and elemental carbon concentrations, as well as coarse mass from 2002 to 2015 (Gebhart et al., Journal of the Air & Waste Management Association, 68, 477–493, 2018).

Although oil and gas activities have led to increases in particulate matter, the impact has been at least partially offset by a concurrent reduction in emissions from coal-fired electric generating stations. This information suggests that oil and gas emission are currently impacting air quality and anthropogenic haze levels in Theodore Roosevelt NP. Based on future year emission inventory projections, it is likely the impacts from oil and gas emissions will continue throughout the planning period.

Montana's Regional Haze State Implementation Plan for the Second Planning Period
Compilation of Federal Land Manager and Public Comments and Montana's Responses Thereto

The following appendices contain comments received during the formal FLM comment period, September 27, 2021 - November 22, 2021 (Appendix F) and during the official public comment period, February 3, 2022 – March 4, 2022 (Appendix H).

Appendix G contains documentation of Montana's public comment period and hearing.

Appendix I contains Montana's response to comments received during the formal FLM comment period and the official public comment period.

APPENDIX G – PUBLIC COMMENT PERIOD AND PUBLIC HEARING DOCUMENTS

1- PUBLIC NOTICE

MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY

PUBLIC NOTICE

The Department of Environmental Quality (DEQ) is inviting public comment on Montana's Regional Haze State Implementation Plan for the 2nd Implementation Period (RH SIP). The purpose of the Regional Haze Program is to improve visibility in wilderness areas and national parks with the goal to attain natural visibility conditions by 2064. Montana's RH SIP outlines a plan for the period 2018 – 2018 and addresses the requirements of the federal 1999 Regional Haze Rule as amended in 2017.

The DEQ will accept public comment for 30 days beginning on Thursday, February 3, 2022 through Friday, March 4, 2022. All comments received will be addressed prior to submitting the RH SIP to the Environmental Protection Agency (EPA) as a revision to the Montana State Implementation Plan (SIP).

Interested persons may view the proposed SIP revision on DEQ's website at: http://deq.mt.gov/Public/publiccomment or may call the Department at 444-9741 to have copies made available for their inspection.

Interested parties may submit written comments concerning the SIP revision to DEQ by:

- the DEQ public notice website: http://deq.mt.gov/Public/publiccomment
- addressing them to Rhonda Payne, MT DEQ AQB, 1520 E 6th Avenue, Helena, MT 59620-0901;
- faxing them to 406-444-1499; or
- sending them via email addressed to repayne@mt.gov.

DEQ will hold a public hearing on the RH SIP on February 23, 2022 in Room 40 of the Montana DEQ – Lee Metcalf Building (1520 E. 6th Avenue, Helena, MT 59601) from 10:00 a.m. to 11:30 a.m. An online option will also be available:

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From:	Payne, Rhonda
To:	Payne, Rhonda
Subject:	RE: Regional Haze Public Comment Period Open
Date:	Monday, June 20, 2022 5:24:40 PM

From: Montana DEQ <montanadeq@announcements.mt.gov>
Sent: Friday, February 4, 2022 2:01 PM
To: Ulrich, Liz <EUlrich2@mt.gov>
Subject: Regional Haze Public Comment Period Open

Montana Department of Environmental Quality

Air Quality Interested Parties

The Department of Environmental Quality (DEQ) is inviting public comment on Montana's Regional Haze State Implementation Plan for the 2nd Implementation Period (RH SIP). The purpose of the Regional Haze Program is to improve visibility in wilderness areas and national parks with the goal to attain natural visibility conditions by 2064. Montana's RH SIP outlines a plan for the period 2018 – 2028 and addresses the requirements of the federal 1999 Regional Haze Rule as amended in 2017.

The DEQ will accept public comment for 30 days beginning on Thursday, February 3, 2022 through Friday, March 4, 2022. All comments received will be addressed prior to submitting the RH SIP to the Environmental Protection Agency (EPA) as a revision to the Montana State Implementation Plan (SIP).

Interested persons may view the proposed SIP revision on DEQ's website at: http://deq.mt.gov/Public/publiccomment or may call the Department at 444-5287 to have copies made available for their inspection.

Interested parties may submit written comments concerning the SIP revision to DEQ by:

- the DEQ public notice website: http://deq.mt.gov/Public/publiccomment
- addressing them to Rhonda Payne, MT DEQ AQB, 1520 E 6th Avenue, Helena, MT 59620-0901;
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This email was sent to eulrich2@mt.gov using GovDelivery Communications Cloud, on behalf of: Montana Department of Environmental Quality · 1520 E 6th Ave. · Helena, MT 59601

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2 - REQUEST FOR EXTENSION OF COMMENT PERIOD

February 10, 2022

Via electronic mail

Rhonda Payne
Montana Department of Environmental Quality
Air Quality Bureau
1520 E 6th Avenue
Helena, MT 59620-0901
repayne@mt.gov

Re: **Requesting Extension of Comment Period for Montana's Regional Haze State Implementation Plan for the Second Implementation Period.**

Dear Ms. Payne,

On behalf of Citizens for Clean Energy, Coalition to Protect America's National Parks, Great Burn Conservation Alliance, Montana Environmental Information Center, Montana Health Professionals for a Healthy Climate, National Parks Conservation Association, Natural Resources Defense Council, Northern Plains Resource Council, Park County Environmental Council, Sierra Club, and 350 Montana (the "Organizations"), we request that Montana Department of Environmental Quality (DEQ) grant an extension on the public comment deadline and public hearing date for Montana's Regional Haze State Implementation Plan ("SIP") for the Second Implementation Period, currently noticed for public comment.[i] Specifically, we ask that the current date of a public hearing, Wednesday, February 23, 2022, be extended to at least Wednesday, March 16, 2022, and the current deadline for comments, Friday, March 4, 2022, be extended to <u>Friday, April 18, 2022.</u>

For review of the proposed SIP, DEQ provided interested stakeholders with just 31 days to evaluate and provide comment regarding hundreds of pages of legal and technical analysis, as well as nearly 200 pages in additional consultation documents.[ii] Given the scope, volume, and complexity of this information, the Organizations believe that the current comment period is not sufficient to fully analyze the potential impacts of the proposed SIP and provide meaningful comment. Reviewing DEQ's legal and technical analysis along with its modeling, conducting any analysis of our own, and developing comments merits more time than allowed by the current comment period, which ends on March 4, 2022.

An extension of time will not adversely impact any other party. We understand and appreciate that DEQ has provided periodic stakeholder updates throughout the planning process, but we have not had access to the proposal before now. A 45-day extension of the deadline will not prejudice any regulated entity and will not materially affect DEQ's ability to submit its SIP to EPA within a reasonable time.

Conversely, given the scope and complexity of the proposed SIP, the current deadline for comments will effectively preclude the Organizations from reviewing all of the relevant technical data supporting the rule, fully analyzing those voluminous files, and providing meaningful legal and technical comments. Moreover, the short timeframe between the rule announcement and the scheduled February 23rd public hearing simply does not provide sufficient time for the public to analyze the complex proposal, provide meaningful input and arrange for attending the hearing. Furthermore, if finalized, the proposed SIP will adversely affect the Organizations' interests in pollution reduction, the environment, as well the health and welfare of our members and their use and enjoyment of protected national parks and wilderness areas.

We respectfully ask that you grant our request by Wednesday, February 16, 2022, so that we can plan our comments most efficiently.

Respectfully submitted,

Richard D. Liebert
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Citizens for Clean Energy, Inc.
Great Falls, MT
wwranch@3rivers.net

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[i] See public notice: https://deq.mt.gov/News/publiccomment-folder/news-article154
[ii] See Montana's Proposed SIP and appendices:
https://deq.mt.gov/files/Air/AirQuality/Documents/RegionalHaze/StateOfMontanaRegionalHazeSIP_2022.pdf,
https://deq.mt.gov/files/Air/AirQuality/Documents/RegionalHaze/MontanaRH_SIP_Appendices_2022.pdf

DEQ
Montana Department
of Environmental Quality

Air, Energy & Mining Division

Via electronic Mail

Anne Hedges
Montana Environmental Information Center
P.O. Box 1184
Helena, MT 59624
ahedges@meic.org

Re: Response to: Request for Extension of Comment Period for Montana's Regional Haze State Implementation Plan for the Second Implementation Period.

Dear Ms. Hedges,

Thank you for submitting your request for extension of the public involvement timeframe for Montana's Regional Haze State Implementation Plan for the Second Implementation Period (RH SIP).

Montana Department of Environmental Quality (DEQ) will extend the RH SIP public comment period through Monday, March 21, 2022. Additionally, DEQ will move the date of public hearing to Friday, March 18, 2022. More details on time and location of the hearing will be forthcoming.

DEQ will notify all interested parties of the public comment period extension and the change of hearing date. This update will go out via email and will be posted on our website at https://deq.mt.gov/public/publiccomment.

DEQ appreciates your participation in the public comment process. If you have any additional questions, please feel free to contact me.

Regards,

Bo Wilkins
Air Quality Bureau Chief
(406) 444-0286
bo.wilkins@mt.gov

From: Payne, Rhonda
To: Payne, Rhonda
Subject: RE: Courtesy Copy: Montana Regional Haze SIP Public Participation - UPDATE
Date: Monday, June 20, 2022 5:31:18 PM

From: Montana DEQ <montanadeq@announcements.mt.gov>
Sent: Monday, February 14, 2022 4:54 PM
To: Ulrich, Liz <EUlrich2@mt.gov>; Davin, Moira <Moira.Davin@mt.gov>; Kathryn.Callon@mt.gov; Velasquez, Rina <RVelasquez@mt.gov>; Harbage, Rebecca <RHarbage@mt.gov>; Payne, Rhonda <repayne@mt.gov>; Danielson, Nicholas <Nicholas.Danielson@mt.gov>
Subject: Courtesy Copy: Montana Regional Haze SIP Public Participation - UPDATE

This is a courtesy copy of an email bulletin sent by Liz Ulrich.

This bulletin was sent to the following groups of people:

Subscribers of Air - AQ Interested Parties or Air - Clean Air Act Advisory Committee (855 recipients)

Montana Department of Environmental Quality

Montana Regional Haze SIP Public Participation - UPDATE

The public comment period for our Montana Regional Haze State Implementation Plan (RH SIP) has been extended to **March 21, 2022**.

The date of public hearing has been moved to **March 18, 2022**.

As a reminder - Interested persons may view the proposed SIP revision on DEQ's website at:

http://deq.mt.gov/Public/publiccomment or may call DEQ at 444-5287 to have copies made available for their inspection.

Interested parties may submit written comments concerning the SIP revision to DEQ by:

- addressing them to Rhonda Payne, MT DEQ AQB, 1520 E 6th Avenue, Helena, MT 59620-0901;
- faxing them to 406-444-1499; or
- sending them via email addressed to repayne@mt.gov.

The public hearing will take place on March 18, 2022 in Room 40 of the Montana DEQ – Lee Metcalf Building (1520 E. 6th Avenue, Helena, MT 59601) from 1:30 p.m. to 3:00 p.m. An online option will also be available:

Microsoft Teams meeting

Join on your computer or mobile app

Click here to join the meeting

Join with a video conferencing device

291818717@t.plcm.vc

Video Conference ID: 119 441 553 5

Alternate VTC instructions

Or call in (audio only)

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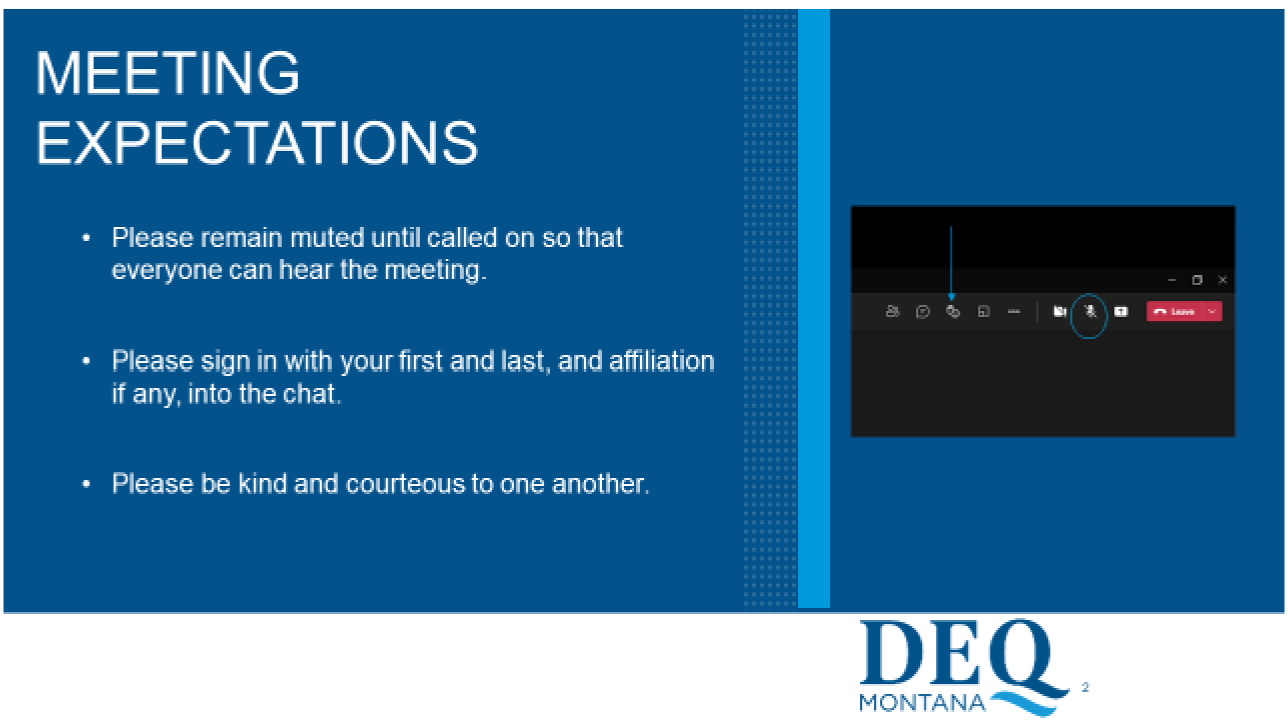
3 - PUBLIC HEARING PRESENTATION



AGENDA

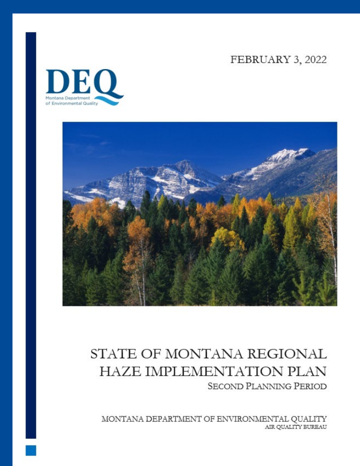
- Presentation
- Public Comment

3

2018 – 2028 Regional Haze Implementation Plan for Montana

Public Hearing

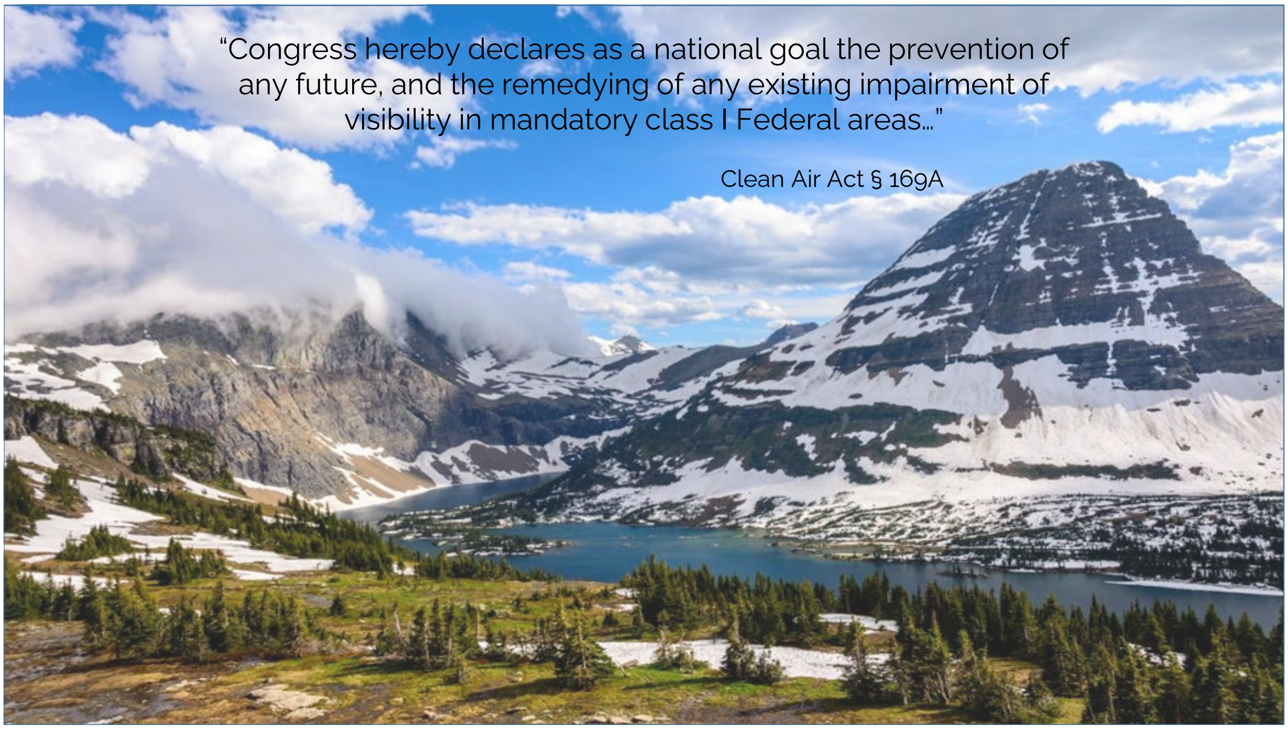
March 18, 2022



FEBRUARY 3, 2022

STATE OF MONTANA REGIONAL HAZE IMPLEMENTATION PLAN
SECOND PLANNING PERIOD

MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY BUREAU


"Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing impairment of visibility in mandatory class I Federal areas..."
Clean Air Act § 169A


Mandatory Class I Areas
NPS Unit
USFS Unit
FWS Unit
0 125 250 500
Kilometers

Objective of Regional Haze Rule

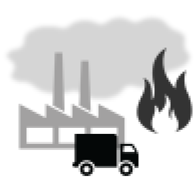
- Establish a regulatory framework for states to address regional haze with the goal of remedying existing and preventing future visibility impairment in mandatory Class I areas.
- Attain 'natural conditions' by 2064
- States submit implementation plans to EPA that cover a 10-year period
- States coordinate with federal land managers to address visibility issues, ensuring that the clearest days don't get worse and that reasonable progress in improving the most impaired days is being made.

DEQ

What is Haze?

Haze is visibility impairment, which means any humanly perceptible difference in visibility from what would naturally exist.

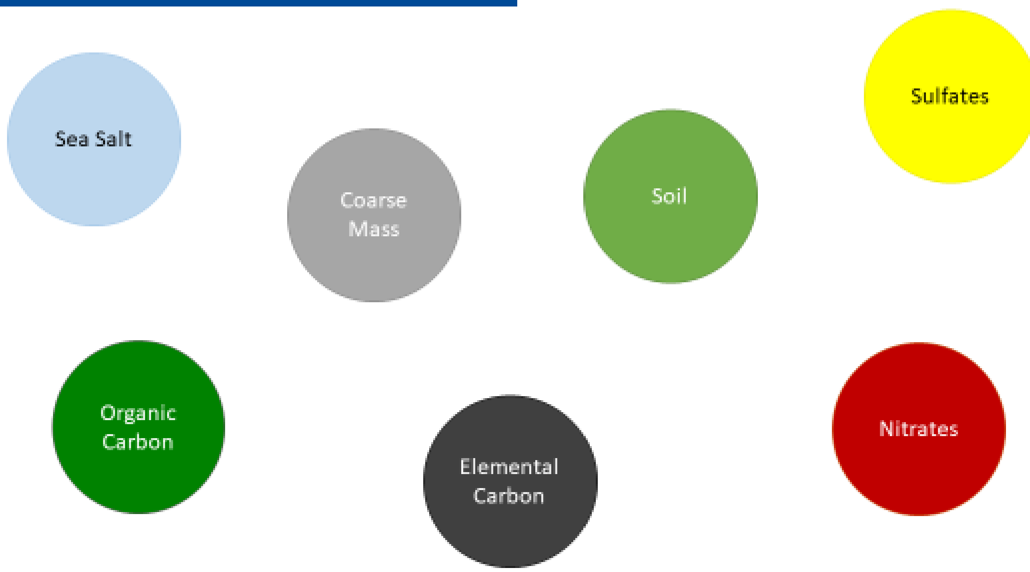
Haze is caused by tiny particles in the air affecting the way light reaches our eyes.

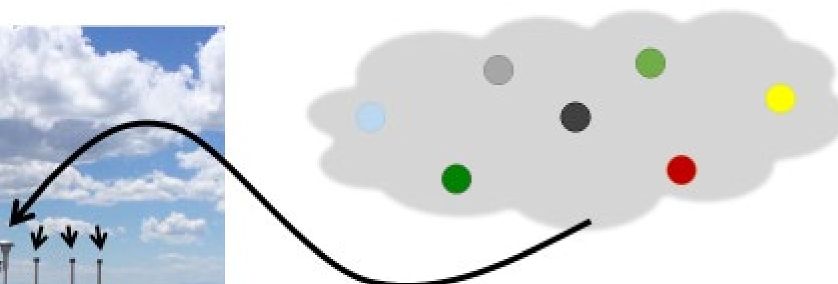


Haze-causing particles come from a variety of sources, including vehicle emissions, large and small stationary sources, wildfires and prescribed fires, and dust.

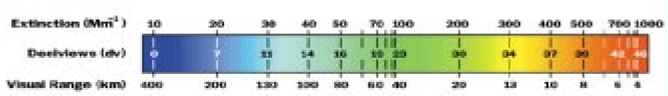
DEQ

Measuring Haze

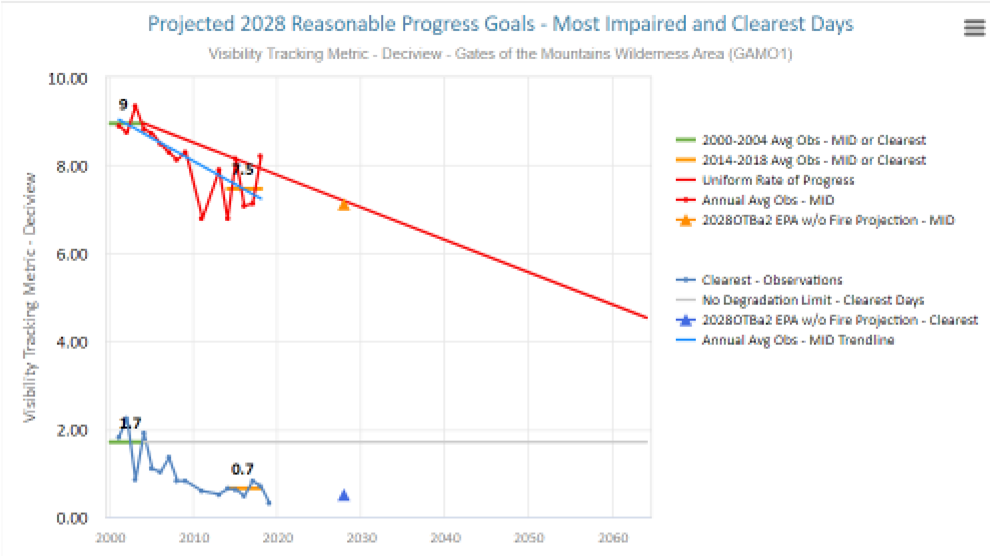




Light Extinction is the amount of light lost as it travels over a distance.

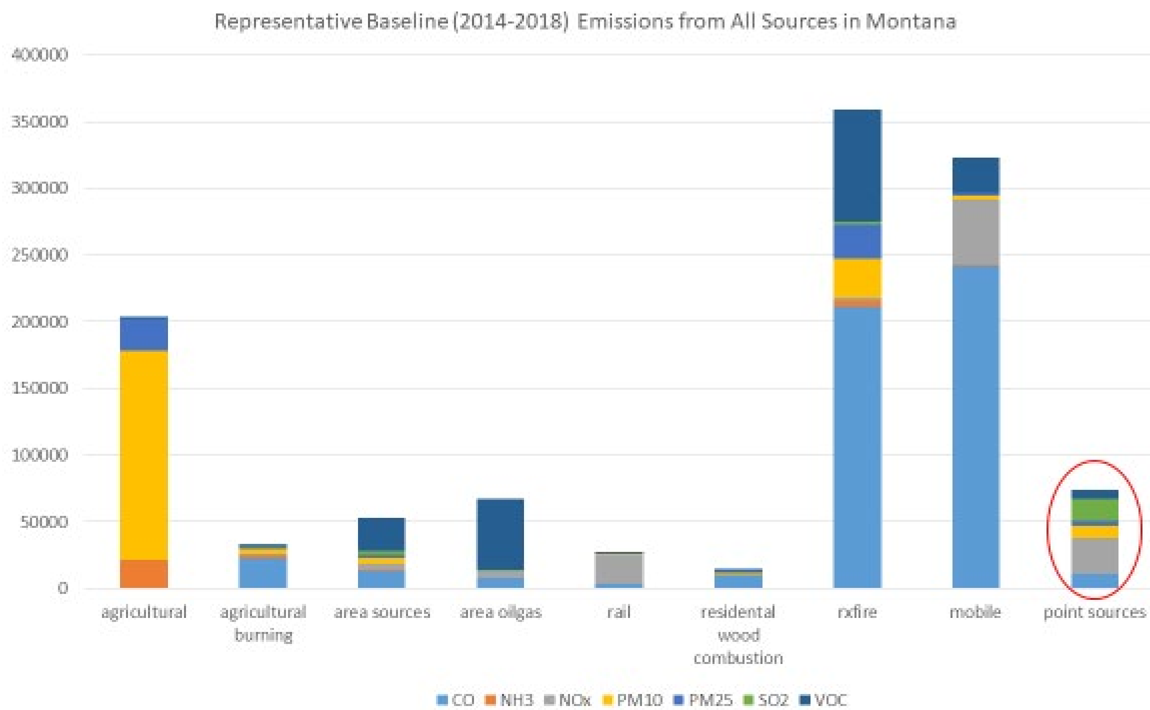


Regulatory Framework



Requirements of RHR

- Visibility Analysis
  - Baseline, current and natural conditions for MT CIAs
  - What particulate species attributed to anthropogenic sources impact MT CIAs
- Emissions Analysis and Long Term Strategy (LTS)
  - Develop a long-term strategy to reduce emissions that contribute to visibility impairment
- Modeling of LTS to set Reasonable Progress Goals (RPGs)



Sources evaluated in this planning period

271
Permitted Stationary Facilities

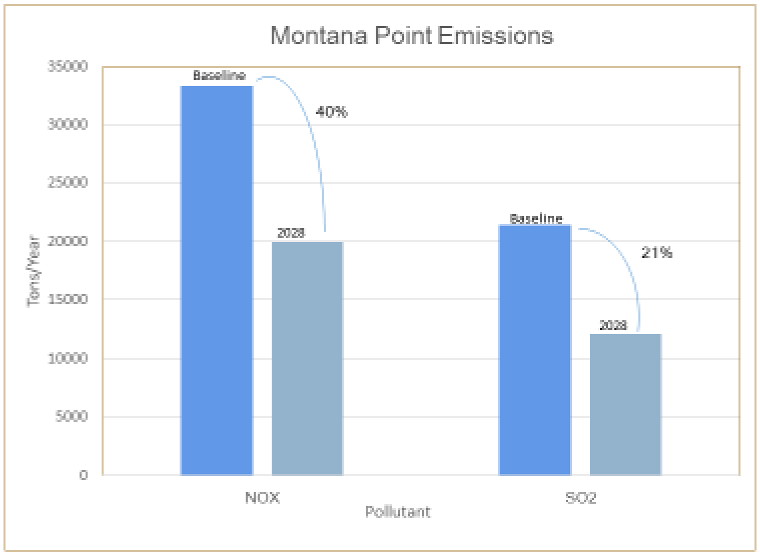
2014-2017
Average Annual Emissions (TPY):

NO_x: 25,027
SO_2: 15,537
NO_x+SO_2 = 40,594

	FACILITY_NAME	2014-2017 Average Emissions NOx+SO2	Nearest CIA	Distance to CIA (km)	2014-2017 Q/D Q = NOx+SO2	
1	COLSTRIP STEAM ELECTRIC STATION #4	6,477.31	U.L. Bend	198.9	32.57	
2	COLSTRIP STEAM ELECTRIC STATION #3	6,239.26	U.L. Bend	198.9	31.37	
3	WEYERHAEUSER-CFALLS	984.36	Glacier	13.3	74.01	
4	ASH GROVE CEMENT	1,235.11	GATES	30.6	40.36	
5	MDU - LEWIS & CLARK STATION	1,052.28	Teddy Roos	51.8	20.31	
6	TRIDENT	1,488.39	Yellowston	97.4	15.28	
7	YELLOWSTONE POWER PLANT	2,136.33	Absaroka	143.8	14.86	
8	ROSEBURG FOREST PRODUCTS	302.61	Selway Bitt	26.6	11.38	
9	COLSTRIP ENERGY LTD PARTNERSHIP	1,935.61	U.L. Bend	188.7	10.26	
10	MONTANA SULPHUR & CHEMICAL	1,310.27	Absaroka	137.5	9.53	Q/d Threshold= 9
11	GRAYMONT WESTERN US INC	524.23	GATES	57.1	9.18	
12	EXXONMOBIL BILLINGS REFINERY	1,034.41	Absaroka	143.7	7.20	Q/d Threshold= 7
13	CHS INC REFINERY LAUREL	628.73	Absaroka	113.5	5.54	
14	F.H. STOLTZE LAND AND LUMBER CO	75.22	Glacier	14	5.37	
15	SIDNEY SUGAR FACILITY	268.79	Teddy Roos	51.9	5.18	
16	N. BORDER PIPELINE CO STA. 3	95.76	Medicine L	19.8	4.84	
17	BILLINGS REFINERY	644.92	Absaroka	143	4.51	Q/d Threshold= 4
18	WEYERHAEUSER-EVERGREEN	134.32	Glacier	30.5	4.40	
19	BLAINE COUNTY #1	512.21	U.L. Bend	134.1	3.82	
20	ROCKY MOUNTAIN POWER	492.78	Absaroka	183.6	2.68	
21	WESTERN SUGAR COOPERATIVE	358.76	Absaroka	138.2	2.60	
22	CALUMET MONTANA REFINING	171.06	GATES	76	2.25	
23	REC ADVANCED SILICON MATERIALS FACILITY	68.25	Anaconda-I	37.8	1.81	
24	STILLWATER MINE	64.15	Yellowston	39.3	1.63	
25	ROCKY MOUNTAIN LABORATORIES FACILITY	13.39	Selway Bitt	8.3	1.61	
26	CONTINENTAL PIT	82.63	Anaconda-I	51.9	1.59	
27	BAKER PLANT	126.82	Teddy Roos	80.2	1.58	
28	BASIN ELECTRIC POWER COOPERATIVE	33.38	Medicine L	21.2	1.57	
29	ROSEBUD COUNTY WESTERN ENERGY MINE	311.46	U.L. Bend	199.7	1.56	

DEQ

Emissions and Modeling Data



Closed sources

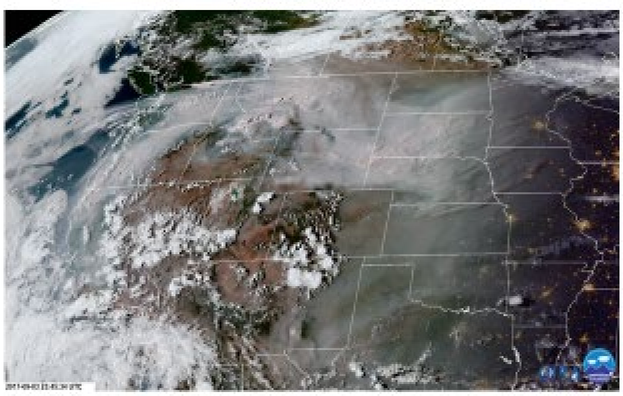
- Colstrip Units 1 & 2 (-10,156 tpy average NOx + SO2)
- J.E. Corette (-2,809 tpy average NOx + SO2)
- MDU Lewis & Clark (-1,052 tpy average NOx + SO2)

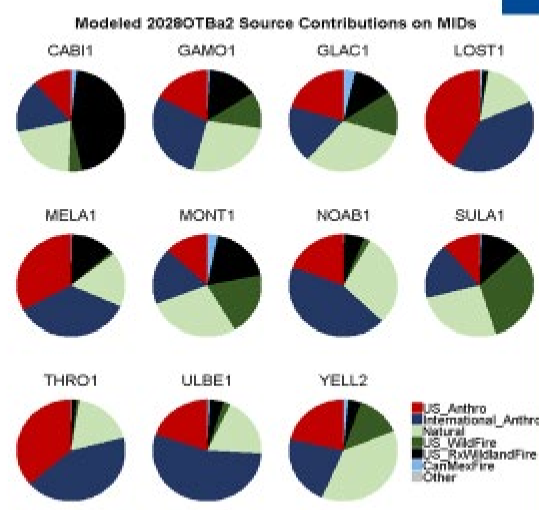
Ongoing pollution control programs

DEQ

Other Considerations

September 3, 2017 – Wildfire Smoke Impacts Across the West





Sources that Contribute to Haze in Montana

DEQ

Conclusions & Timeline

The current rate of visibility improvement projected by the end of the planning period is reasonable for making progress toward the 2064 end visibility goal.

April:

- Summarize and respond to comments received. Route to Governor's office for signature.

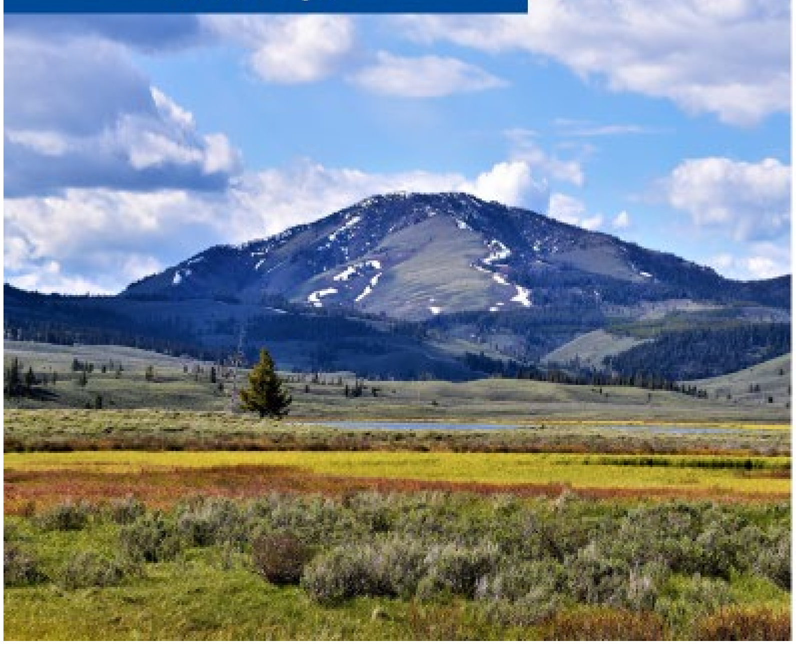
May:

- Submit to EPA.

After May:

- EPA has **6 months** from submittal to perform a SIP completeness determination.
- EPA has **12 months** to act on our SIP.

Contact Info



Rhonda Payne – Air Quality Planner
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(406) 444-5287

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(406) 444-6257

PUBLIC COMMENT

DEQ MONTANA

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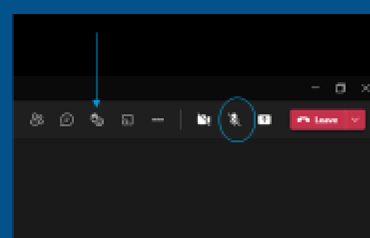
PUBLIC COMMENT

- Use the "raise hand" feature in the app to indicate that you would like to provide comment. In the room, please sign up.
- If you are called on to speak, please unmute and identify yourself by stating your first and last name, whether in the room or online.
- Please keep comments to 3 minutes.
- Joining by phone?
  - Press *9 to raise your hand.
  - Press *6 to mute/unmute yourself.



DEQ MONTANA

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PUBLIC COMMENT

Comments Due March 21, 2022
repayne@mt.gov

Mail:
Rhonda Payne
MT DEQ AQB
1520 E 6th Ave
Helena, MT 59620-0901

DEQ
MONTANA

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4 - PUBLIC HEARING TRANSCRIPT

STATE OF MONTANA

DEPARTMENT OF ENVIRONMENTAL QUALITY

MONTANA'S REGIONAL HAZE)
STATE IMPLEMENTATION PLAN)

TRANSCRIPT OF PROCEEDINGS

BE IT REMEMBERED, that the proceedings in the above-captioned matter was heard in Room 45 of the Metcalf Building, 1520 East Sixth Avenue, Helena, Montana, and via Zoom, on the 18th day of March, 2022, beginning at the hour of 1:30 p.m., before Laurie Crutcher, Registered Professional Reporter, Notary Public.

* * * * *

WHEREUPON, the following proceedings were had and testimony taken, to-wit:

* * * * *

MS. DAVIN: Okay. Has everyone on Zoom signed into the chat, and also the sign-in sheet in the room?

This hearing is recorded, so I'm going to go ahead and start the recording and the live transcription. All right. Thanks, everyone, for joining us today. My name is Moira Davin, and I'm the Public Relations Specialist for DEQ in the Public Policy Division. I will preside over today's public hearing.

Thank you for attending this hearing before Montana DEQ. And the purpose today is to hear comments from any interested person regarding Montana DEQ's Regional Haze State Implementation Plan for the second planning period.

So with that, would you please advance the slide, Rhonda.

Great. So as I mentioned, this hearing is being recorded. Please remain muted until called on to speak so that everyone can hear the meeting clearly, and doesn't have any background echoing.

Please sign in to the chat with your first and last name and affiliation, if any, for those online. Those in the room, please sign in to the sign-in sheet located in the front of the room. And as always, please be kind and courteous to one another. Next slide, please.

So today we will hear a presentation from Montana DEQ's Air Quality staff, and then we'll begin the public hearing portion of this meeting.

Montana DEQ provided a draft of the Regional Haze State Implementation Plan for public review and comment beginning on February 3rd, 2022. This public comment period will close on Monday, March 21st. So written comments must be received by 11:59 p.m. on the 21st, and both written comments provided by the deadline and oral testimony today receive the same consideration, and will be part of the official record. We do have a Court Reporter in the room with us today as well taking notes of the comments.

If you wish to provide public comment today, if you could please note that on the sign-in sheet, and then for those joining online, if you could please raise your hand for those that

would like to provide comment, and we will go according to those that have raised their hand in that order.

Okay. And I think with that, I'll go ahead and turn it over to our DEQ staff, so they can give a quick presentation on the Regional Haze State Implementation Plan.

MS. PAYNE: Okay. Good afternoon, everybody. My name is Rhonda Payne, and I work for Montana DEQ as an Air Quality Planner. And today I'm going to do a brief, give everybody a brief presentation of our Regional Haze State Implementation Plan for the second planning period.

So the State of Montana Department of Environmental Quality is proposing a revision to the State Implementation Plan or SIP to satisfy the requirements of the Regional Haze rule. What does this mean, and what is required?

In 1977 Congress amended the Clean Air Act with provisions to protect scenic vistas in certain Class 1 areas. In these amendments, Congress declared the following national visibility goal -- on your screen -- the prevention of any future and then remedying of any

existing impairment of visibility in mandatory Class 1 Federal areas, which impairment results from man-made air pollution.

Unlike the other provisions of the Clean Air Act and other pollution measures, the Regional Haze rule focuses on safeguarding nature and ecosystems in protected federal lands, rather than focusing on public health.

The National Ambient Air Quality Standards or NAAQS are the health based standard and apply to certain air pollutants. So said another way, the NAAQS are health based standards, while the Regional Haze rule is a visibility standard applied only to Federal Class 1 areas.

UNKNOWN SPEAKER: Rhonda, sorry to interrupt, but I think we just caught a comment that said that the screen is black, and the presentation is not sharing.

MS. DAVIN: The screen is showing for me. Is anyone else having trouble seeing the screen? I'm seeing comments people can see the screen. For the person who is having trouble seeing the screen, maybe try exiting and coming back in.

UNKNOWN SPEAKER: I think he's good now.

MS. PAYNE: The US EPA adopted the Regional Haze rule in July of 1999, and revised it in January of 2017 to establish comprehensive visibility protection program for the nation's 156 mandatory Class 1 areas shown here.

Of note, the Regional Haze rule is only focused on the original 156 Class 1 areas, and does not include Class 1 Tribal areas. EPA works with Tribes on addressing haze in these areas. And in Montana, you'll see we have twelve mandatory Federal Class 1 areas as shown here.

The objective of the regional haze rule is to establish a regulatory framework for states to address regional haze with the goal of remedying existing and preventing future visibility impairment in mandatory Class 1 areas.

The rule focuses on two issues. First, it establishes the deadline for attaining natural conditions for visibility in Class 1 areas as the year of 2064. Second, it requires the State to show efforts to make reasonable progress at ten year intervals.

Through this iterative planning process, states, along with input from federal land manager partners, address visibility impairment in Class 1

areas, and make reasonable progress toward achieving natural visibility conditions. The rule adds to the existing efforts to reduce pollution, including emission controls and other standards.

This rule promotes both flexibility for states, and regional cooperation with other states in developing strategies under a multi-state approach.

So quickly, what is haze? Haze is visibility impairment that is humanly perceptible from natural conditions, caused by particulates in the air that scatter and/or absorb light, and these haze causing particulates come from numerous pollution sources, both natural and man-made.

There are different types or species of particles. Sulphates and nitrates are typically anthropogenic or man-made contributions, and they are depicted here in red and yellow; and organic carbon and elemental carbon, green and black here, mostly can be considered smoke from wildfire and prescribed fire.

And in Montana all these particles contribute to haze in different amounts at different times of the year, so think wildfire smoke in summer, and to some extent in different

places, we often see that carbon species impact our western Class 1 areas more than they do in eastern Class 1 areas.

Haze particles are measured at a network of federally managed monitoring sites across the country, and here is a site near Gates of the Mountains just north of Helena. And basically you can see the intakes from the four monitors that measure all those different types of particles.

To calculate visibility or haze, the measured concentrations of each particle are entered into a formula to estimate light extinction, which is the amount of light that is lost as it travels over a distance. When more light is lost, things appear hazy, and we can't see as far.

A couple of other quick terms to mention. These are the deciview and visual range. A deciview is the main unit EPA uses to represent haziness or how far you can see. And you can see in the scale here, one deciview of change in visibility is perceptible to the human eye; and the higher the number, the hazier it is, and the less you can see.

Visual range is a helpful translation

for most of us, and that can tell us approximately that distance that these technical terms relate to.

The way the State can examine how they're making progress in reducing haze is by using something called a glidepath or a uniform rate of progress. This glidepath starts with the 2000 to 2004 average of monitoring data presented in deciviews, as you can see here on the "Y" axis, as the baseline. From the baseline, a straight rate of progress line is drawn to the end of 2064 year.

To meet the planning requirements in the rule, states conduct analysis of visibility in each Class 1 area, identifying the available reasonable measures to reduce haze, and implement these measures as part of our long term strategy for the planning period.

The implemented measures establish the required reasonable progress goals for each Class 1 area. The RPG -- in this diagram represented as interim goals -- are the visibility improvement benchmarks on the glidepath towards the long term goal of natural conditions in 2064.

The content of the long term strategy

Page 10

and the resultant RPG's, or reasonable progress goals, are key strategy components for states, and must be included in the SIP. States are also required to assess progress halfway through the ten year implementation period, a process that is intended to keep states on target to meet the ten year goals established for each Class 1 area.

And taking this concept a step further, we can examine a real glidepath for Gates of the Mountains Wilderness Area. The red jagged line represents that actual monitoring data for the most impaired days on an annual average. The blue jagged line below that represents the annual average of the clearest days.

The most impaired and the clearest days are a metric EPA created in the Regional Haze rule with the express intent of providing a way for states to show that visibility on the haziest days is getting better, while not messing up the best or the clearest days.

Next, we show our RPG, our Reasonable Progress Goals, for the most impaired days and the clearest days. You can see that on the screen by the orange and blue diamonds. These goals come from regional modeling, and they take into account

Page 11

projected emissions at the end of our planning period.

In our SIP we identify some key requirements of the rule. These are a visibility analysis in which we look at the baseline current and natural conditions for Montana Class 1 areas, and what measured particulate species are found there that are likely due to man-made sources.

Then we evaluate the sources of those emissions to determine if additional controls are necessary to make progress. In combination with the statutory emission analyses, states are required to look at emission reductions from the following: Ongoing pollution control programs; smoke management programs; source retirements and replacements; mitigation of construction activities; and the net effect of visibility due to projected changes in emissions. All of these items are balanced to create our long term strategy for the ten year planning period.

These emission reductions that are realized by implementing this strategy are put then into a large scale regional photochemical grid model in order to come up with our reasonable progress goals.

Page 12

The pollution in Montana comes from a wide variety of sources, as shown in this graph. Total tons of emissions are there on the "Y" axis with the sources listed below on the "X" axis. The various pollutants and their amounts make up the colored bars above each source.

Notably missing is wildfire, which had we included it, would be emissions so large that it would potentially skew the "Y" axis presented here.

Montana does not regulate agricultural activities, including ag burning. EPA regulates mobile sources, and to some extent rail, residential wood combustion, and area sources including oil and gas through other parts of the Clean Air Act, including area source MACT and NSPS rules.

The sources in Montana's jurisdiction are prescribed fire under our smoke management program, and industrial stationary or what we call point sources, which are circled here in red.

For purposes of Regional Haze, Montana conducted a source screening to build a list of sources that potentially contribute to haze in a nearby Class 1 area, starting with our permitted

Page 13

point sources.

When we started this analysis, there were around 270 permitted facilities in Montana. The results of our visibility analysis that I mentioned earlier indicated that nitrate and sulphate particles, those represented as yellow and red, from anthropogenic sources were contributing to haze in our Class 1 areas.

Therefore, we looked at sources that emit the precursors to nitrate and sulphate, which are oxides of nitrogen or NOx, and sulphur dioxide or SO2.

The average NOx and SO2 emissions over the baseline period from all permitted sources evaluated at that time was around 40,000 tons per year.

Montana sorted these facilities based on emissions and the proximity to a Class 1 area. This is what is known as a "Q" over "d" analysis where "Q" represents emissions, and "d" is the distance to nearest Class 1 area in kilometers. This analysis roughly correlates with visibility impacts as they would be estimated via an air quality model.

And the list on the left that you see --

excuse me -- on the right is the result of that analysis. So Montana, quote unquote, screened in sources that contribute almost 90 percent of NOx and SO2 by selecting a very low "Q" over "d" of four, which is circled in red.

Many other states close a larger "Q" over "d," thus evaluating a smaller list of sources. We felt it was important to cast a wide net, and evaluate many sources in this ten year planning period.

So seventeen sources, those with the "Q" over "d" of greater than four, were required to submit what's called a four factor analysis that included evaluating, one, the cost of control; two, the time necessary to install controls; three, the energy and non-air quality impacts; and four, the remaining useful life of the source. Then that's how we were able to evaluate the reasonableness of installing additional pollution controls in this planning period.

Now looking at emissions and modeling data. When we look at the emissions in our 2014 to 2018 baseline period compared to what we project emissions to be in 2028, we can see that

NOx is projected to decrease by 40 percent, and SO2 by 21 percent.

And why is this? The main reason is that we've seen a large amount of emission reductions from early closures of coal fired EGU's in Montana. Over 14,000 tons per year of NOx and SO2 combined that were emitted over that baseline period of 2014 to 2018 will essentially be reduced to zero in 2028 due to these closures.

Another reason we are seeing this large reduction is ongoing pollution control programs other than Regional Haze that limit a source's emissions.

These emission reductions from source retirements are necessary to make reasonable progress this round. Montana will submit a mid-planning period progress report, where we will evaluate what emission changes have occurred, and further reductions in emissions. We can also examine whether facilities not screened in this round should be evaluated for additional controls.

Progress in the emission reductions often comes when equipment has exceeded its useful life, and is replaced with more efficient equipment. This will likely be the case for some

of the facilities evaluated for this SIP submittal.

Facilities will make business decisions, now knowing that Montana will be requiring to continue evaluating whether adequate pollution controls are in place to satisfy the reasonable progress under the Regional Haze rule.

And quickly, other important considerations are the sources of emissions that Montana cannot control, both anthropogenic and natural.

And this is a picture of the west in September 2017, and you'll see that wildfire smoke is basically spreading across the nation. Wildfire emissions impact much of the west, and have become a natural part of the summer and fall in Montana. Additional prescribed fire activities are becoming more accepted as a control strategy for wildfire. In Montana, smoke from both wildfire and prescribed fires impact our Class 1 areas.

Additionally, international emissions from Canada and beyond disperse into Montana and have a large impact on our eastern Class 1 areas.

So now you'll see on the right-hand side

both international and the smoke emission contributions can be seen in these pie charts. These charts represent the relative modeled contribution of haze by Class 1 area, and the legend shows what the colors represent with emissions from international anthropogenic sources in dark blue, and emissions from smoke, both wildfire and prescribed fire, in dark green and black. And analyses such as these also help to inform our planning.

In conclusion, technical analyses such as large scale photochemical grid modeling estimate the contribution of these sources, as well as industrial sources in Montana, and project our 2028 visibility to be on track to meet our Reasonable Progress Goals for this planning period.

The timeline moving forward is displayed. We will address comments and update the SIP accordingly, with the goal of submitting to the EPA by May.

Then EPA will review the SIP for both administrative completeness, and then for approvability. There will be a 30 day public comment period during EPA's process when the EPA posts the proposed rulemaking.

So thank you for your attention. Our contact information is listed on the slide, and we will now move forward in the hearing proceedings.

MS. DAVIN: Thank you, Rhonda. We'll go ahead and move into the public comment portion. For those in the room, if you're just joining us, make sure if you want to provide comment to please sign up on the front table; and then for those that are online, please raise your hand.

I do see one phone caller. For that person joining by phone, would you like to make comment? We will add you to the list. You're welcome to unmute now and let us know.

UNKNOWN SPEAKER: No, thank you.

MS. DAVIN: Okay. Great. All right. So anybody online that would like to make comment, please raise your hand, and we'll go in the order addressed. Rhonda, next slide, please.

And as always when we do comment, if you could please state your first and last name, and spell it for our Court Reporter. And please do keep your comments to three minutes, so we can make sure we can hear from as many people as possible.

So with that, we will start with those in the room. Rhonda, do you have the list --

MS. PAYNE: I do.

MS. DAVIN: -- in the room?

MS. PAYNE: Yes, and we have one commenter.

MS. DAVIN: Okay. Do you want to come up to the front podium, and please state your first and last name and spell it.

MS. DUNWELL: Sure thing. Hello, everybody. My name is Mary Ann Dunwell, M-A-R-Y A-N-N, Dunwell, D-U-N-W-E-L-L. Thank you for the opportunity to comment. I'm a State Representative representing House District 84, which is Helena and East Helena.

I appreciate the presentation Ms. Payne presented, and I'd like to comment on this draft plan.

I don't like it. I believe Montana needs a pollution reduction and mitigation plan for our state's largest industrial emitters of greenhouse gases, not the plan that basically purports to do nothing for the next ten years.

When I worked for DEQ more than a decade ago as a public involvement officer, my colleagues

and I lived and worked by DEQ's mission that we protect and preserve a clean and healthful environment for present and future generations.

What happened? Why doesn't DEQ and our current Administration let you in the room here and other colleagues or dedicated State employees do your job to protect our clean and healthful environment?

Imagine how you must feel knowing we're suffering a climate crisis, and your hands are tied, despite working for the very department charged with protecting our clean and healthful environment.

The plant closures that Ms. Payne mentioned aren't even a drop in the bucket to mitigating the climate crisis. The wildfires cited, yes, they're naturally made. However, the genesis is the increase in the greenhouse gases in the atmosphere, which is leading to our climate crisis, so we're seeing wilder wildfires, wilder storms, drought, you name it.

Even the US Chamber of Commerce, a business group, calls for market based approaches to reduce greenhouse gas emissions. Yet in Montana, we do the opposite, and DEQ and the

Administration look the other way.

DEQ forgot to include in its reasoning to EPA that big industrial pollution emitters get a super tax break on pollution control equipment.

As a legislator, I've served on the tax committee all four sessions that I've served. A couple of sessions ago, the majority in the Legislature repealed the tax on pollution control equipment. I vehemently argued and voted against repeal because pollution control is a cost of doing business, especially as we face this climate crisis, or it should be a cost of doing business.

In the Legislature I proposed carbon cost community dividend bills, H. Bill 193 in the 2019 session, and H. Bill 150 in 2020. The bills would have made big industrial polluters pay for their pollution, and pay for the harm they're doing to public health and the polluting of our communities, which is taking place right now under our noses, especially in poorer, more vulnerable communities.

HB-150 and 193 would have slowed climate change, and mitigated harm to people, environment, and our economy. Sadly, the bill never made it out of committee.

As you know, our Montana Constitution guarantees a clean and healthful environment, and legislators like myself have a constitutional responsibility to uphold that guarantee, and so do you. Please don't shirk this responsibility.

Thank you for letting me speak, and thank you for what you do to try to protect a clean and healthful environment.

MS. DAVIN: Thank you. Do we have anyone else in the room that would like to provide comment?

MS. PAYNE: No.

MS. DAVIN: Okay. We'll go ahead and move down our list online. So the next up I have is -- I apologize if I don't say your name correctly -- Lucy Hochschartner. And please state your first and last name and spell it, and you have three minutes.

MS. HOCHSCHARTNER: Hello. Thank you. Can I be heard?

MS. DAVIN: Yes, I can hear you.

MS. HOCHSCHARTNER: Perfect. Thank you. My name is Lucy Hochschartner, L-U-C-Y H-O-C-H-S-C-H-A-R-T-N-E-R. Thank you so much for the opportunity to comment today, and no worries

about the name. It is a hard one.

I'm a volunteer with the Gallatin Valley Sunrise Movement. We're a group of youth fighting for good jobs and clean energy.

I also happen to be a citizen of Bozeman, and a professional athlete. I spend hundreds and hundreds of hours outside every year in our wilderness areas, getting to some of the most remote places on foot. I'm a biathlete, which is cross country skiing and target shooting, so all year you can find me running and skiing all over Montana in our wilderness areas.

And I've seen throughout my life the way that our environment is continually being made a second priority, or a last priority, and we're seeing the impacts of that.

This plan is a disgrace, in that it doesn't actually do anything. I'm only 24 years old, and I've seen these changes, and ten years is almost half of my life thus far. Waiting another ten years is simply not an option.

I hope that we're able to change this plan to require pollution controls from industrial emitters, which are our major emitters, so that young people like me can enjoy wilderness areas in

the way that they were intended, which is that they are untouched. Obviously that includes the air we are looking at and the air we are breathing when we're there.

Thanks so much for the opportunity to comment today. I actually have to run to a ski race, speaking of my athletic life. So I'm going to hang up, but thank you so much for the opportunity to comment.

MS. DAVIN: Thank you, Lucy, and good luck on your race. Next up we have America Fitzpatrick. America, please state and spell your first and last name, and you have three minutes.

MS. FITZPATRICK: Hi. Good afternoon. My name is America Fitzpatrick, America just like the country, A-M-E-R-I-C-A. Fitzpatrick is F-I-T-Z-P-A-T-R-I-C-K. I am the senior program manager for the Energy and Landscape Conservation Program at the National Parks Conservation Association. Thank you for the opportunity to comment today on Montana's Regional Haze State Implementation Plan for the second implementation period.

NPCA is the oldest and largest non-profit advocacy organization for national

parks. We have over 1.6 million members and supporters across the country, and more than 8,200 of them are here right here in Montana.

As you know, Montana boasts eight national park sites, two of which are also Class 1 areas, Glacier and Yellowstone National Parks. They join eight other Class 1 areas managed by the US Fish & Wildlife Service and the US Forest Service across our state.

Haze pollution not only mars scenic views in our national parks, but also harms public health for neighboring communities, and park visitors, and staff, and contributes to the climate crisis. Montanans are all too familiar with our yearly hazy skies produced by drought-fueled wildfires across the west.

The opportunity that our state has right now to clean up pollution from specific industrial sources cannot be missed. The State Implementation Plan currently proposed by the Montana Department of Environmental Quality falls significantly short of the State's obligations to restore clean air in our national parks.

The State improperly concludes that no new reductions in pollution are warranted. If DEQ

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submits the current plan as is to the US EPA, it will not comply with the Clean Air Act and the Regional Haze rule, as it does nothing new to limit haze-causing air pollution.

Of the sixteen sources that DEQ selected for review of emissions reducing measures, three are coal fired power plants that emit 72 percent of Montana's haze-causing air pollution. The Colstrip Steam Electric Station is the eighth worst polluter, haze polluter, in the entire country, and it's outrageous that the State has proposed no new emissions reduction for those dirty coal plants that impacts parks and communities from as far away as southern Colorado.

Moreover, DEQ decided that there is no such thing as a cost-effective pollution control, so they discarded possible pollution control measures that can be acceptable to other states to establish a dollar threshold cost effectiveness. Additionally DEQ inflated their costs of controls calculations.

I live in Three Forks, so just down the road from the GSCC Trident Cement Manufacturing Plant, and we hike right around there at the Headwaters State Park. This plant spews over

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1,300 tons of nitrogen oxide into the air, and every year impacting the air my family and I breathe every day.

I have two kids under six who I hope don't grow up with asthma like I did. We love to spend our time outside, and I can only imagine what amount of pollution they're breathing in every time that we go outside and get in a quick loop there at the headwaters.

Not only does this plan impact my air, but also potentially impacts air in twelve Class 1 areas in Montana and other surrounding states. So NPCA requests that the State significantly revises its draft State Implementation Plan to fulfill its obligations under the Clean Air Act.

Specifically we request that you require emission controls for not only the three power plants the State selected for review and planning period, but also all of the state refineries and cement kilns selected for review.

Also require the Hardin Generating Station to conduct a review of emissions-reducing measures, given its revival of a cryptocurrency mining facility, and a significant increase in emissions in the past year; as well as establish a

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cost-effective threshold for reasonable progress, and one that is in line with other states like Colorado's threshold of $10,000 per ton of pollution; as well as require to correct the inflated costs of controls calculations, and to thoroughly assess environmental justice and impacts of the implementation plan on our communities.

The Clean Air Act Regional Haze rule is an effective program that has resulted in real measurable and noticeable improvements in national park visibility and air quality.

The State Implementation Plan developed under the Regional Haze rule is an opportunity and an obligation for states, including Montana, to reduce pollution in their borders, to help restore clean and clear skies at protected national parks, wilderness areas, and within our community.

Thank you for your time and the opportunity to provide public testimony today. I'll be submitting my testimony in written form as well, and I look forward to reviewing improvements to these plans. Thank you.

MS. DAVIN: Thank you, America. Next up we have Susan Evans. Susan, please say and spell

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your first and last name. You have three minutes.

MS. EVANS: I'm Susan Evans, S-U-S-A-N E-V-A-N-S. I'm a former school teacher in Polson, Montana. I grew up in Billings, I graduated from college there, and I'm here today because my brother died of COPD. He lived mostly in the Billings and Laurel areas, and I'm convinced that air pollution contributed to his early death.

The area around Colstrip has recognizably devastating numbers of asthma cases, especially among their children. I'm convinced that the pollution coming from the Colstrip facility severely aggravates that life threatening illness.

We need pollution control at all Montana refineries, all our coal fired plants, and cement kilns. We must have strict measurable standards in place right now. We cannot wait until 2028 and then say "Oops. We should have acted on this years ago."

The point of having standards and regulations is to avoid damage before it becomes a problem. Thank you for protecting the lives and well-being of all our Montana citizens. We need your quick and decisive action in reducing air pollution. Thank you.

MS. DAVIN: Thank you, Susan. Next up we have Evan Romasco-Kelly. If you could please say and spell your first and last name, and you have three minutes.

MR. ROMASCO-KELLY: Thank you. My name is Evan, E-V-A-N, Romasco-Kelly, R-O-M-A-S-C-O hyphen K-E-L-L-Y. Thank you so much for the opportunity to comment today.

I, like Lucy, am a volunteer with Gallatin Valley Sunrise Movement, a group of young people trying to create a livable future for ourselves amidst a very frightening outlook for the next ten years and beyond.

And frankly I'm galled to see this plan purporting to work towards reasonable progress on haze by doing nothing, by relying on closures that are already in progress, or already have been, when we see that other facilities like the Hardin Generating Station, which were thought to be closed, can be brought back by business interests for cryptomining in Montana.

We do not have time to allow more pollution to go through for ten years, for five years, without any sort of control. It's

completely backwards. We really absolutely need to require restrictions -- or not restrictions -- but pollution controls, and we need to do it now. We don't have the time to wait.

So I really request that DEQ goes back and revises this plan to require emission controls across Montana, and like others have stated, to establish things like a cost threshold for determining pollution control efficacy.

The fact that we have no cost-effective pollution controls is ridiculous. That is not the state of the world in 2022. There are cost-effective pollution controls, and companies do need to pay in order to pollute.

We also need to investigate and make sure, as others have stated, that the health impacts of this pollution are being mitigated, and that we are not allowing the Clean Air Act to be used as a vehicle to allow people to pollute, when really it should be allowing people to survive and live, especially if they live close to Class 1 areas, which most folks in Montana do.

As an avid outdoor recreator, I spend time in these areas, and I've seen how the air quality has degraded, and if it's degraded there,

that means it's horrible in other parts of the state, and I've noticed that, too, myself.

So please, I humbly request and urge you to go back and revise this plan, require pollution controls, and do more to help the state of Montana have a healthful climate going forward. Thank you so much.

MS. DAVIN: Thank you, Evan. Next up we have Anne Hedges. Anne, please say and state, spell your first and last name and affiliation, if any.

MS. HEDGES: Good afternoon. I'm Anne Hedges, A-N-N-E H-E-D-G-E-S, with the Montana Environmental Information Center.

And I just want to start out by saying thank you to DEQ for extending the public comment period. This is a really long and complex SIP, and the related federal land manager's comments is a lot to get through, and I think that the public comments are going to be more useful to you because of that. So I really appreciate the fact that you're willing to take a little more time to let the public analyze this, what you've proposed.

That said, I'm not very pleased with it. I apologize. But it appears that DEQ only

completed half of its job, and it seems to allow companies to determine whether or not they wanted to install pollution control measures at their facilities.

DEQ failed to justify much of its rationale. For example, I just got today EPA's comments, and I just want to read you two things.

First I would say that it's quoting what DEQ said, that future projected economics of coal and the need for stable baseload generation, as well as a shift in electrical generation away from coal towards renewable and natural gas were reasons why further controls, including emission limit tightening, are not reasonable, but it is not clear why a preference to favor one form of electricity generation over others is relevant in determining reasonable progress towards the national visibility goal.

In other words, EPA is questioning, as we do, why the State is going outside the framework of the Regional Haze Program to decide that no further analysis or emission controls are necessary.

DEQ failed to establish, first and foremost, a cost-effective threshold for emission

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reductions, and instead relies on closure of a few coal-fired units, either to eliminate its obligation to reduce haze forming emissions. This reliance is misguided, and it was inappropriate.

DEQ must establish a cost-effectiveness threshold. Without it, it is impossible to know if pollution controls are cost-effective, and therefore it's impossible for DEQ to actually guarantee it's complying with the four factor analysis that is required in the Regional Haze Program.

DEQ's conclusion that it will meet the required uniform rate of progress and no emission reductions are necessary is inadequate. Uniform rate of progress is a tool to analyze the State's program. It is not the same as complying with the required four factor analysis.

DEQ relies heavily on future plant retirement to meet its obligation, but future retirements are far from certain. Northwestern's most recent announcement shows that for net zero by 2050, it shows that it does not intend to close Colstrip until 2042.

CELP and YELP, Colstrip Energy Limited Partnership and Yellowstone Energy Limited

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Partnership, may no longer sell power to Northwestern within this planning period, but as we have seen recently, there are other companies who may be interested in that power.

There is no surety that these two facilities will close anytime in the next decade. Hardin was going to close, but is now dedicated to cryptocurrency. Since China banned cryptocurrency, there has been an increased interest in Montana as a location for this type of business.

Without enforcible closure dates for facilities within this planning cycle, it is inappropriate for DEQ to assume that facilities will close, and thereby determine that pollution controls would not be cost-effective.

We are concerned that DEQ has used this type of misguided analysis to eliminate consideration of cost-effective pollution controls. We're also concerned that DEQ has underestimated the removal efficiency of certain pollution control technology at sites such as both of the state's cement plants and fossil fuel burning plants, as well as overestimated the cost of those pollution controls.

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DEQ should not include non-existing costs in the analysis, such as property taxes, as pointed out by the federal land managers, or use inflated costs. For example, they use inflated prime interest rate.

None of the sources chosen by DEQ completed an accurate four factor analysis, and DEQ must either require them to do so, or it should explain itself, or it should do it itself.

In addition, DEQ also failed to analyze the impact of the oil and gas factor entirely on haze, and whether emission reductions are necessary. Montana must either explain why it's let that sector off the hook, or to present an analysis for public review. DEQ should also require four factor analysis for the newly revised Hardin Generating Station.

DEQ relies on NAAQS for public health protection, but NAAQS are only as good as the number and placement of monitors within the state. We know that DEQ does not have sufficient funds to monitor as it should to guarantee protection in the NAAQS.

Regional Haze is focused on Class 1 areas, but it also protects public health. DEQ

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wrongly uses the economy to dismiss cost-effective pollution controls, but then refuses to use public health protections to allow such reductions. It doesn't make any sense, and it seems like its priorities are misplaced.

Montana's outdoor economy accounted for 4.3 percent of Montana's gross domestic product in 2020, the highest percentage of any other state, and we have one of the highest recreation employment rates in the nation.

Considering the value of recreation and tourism in Montana's economy, it is appropriate to set cost-effective thresholds similar to that established in Colorado of $10,000 per ton. We've seen the effect that bad air quality has on national park attendance, such as Glacier. This program will help alleviate bad air quality --

MS. DAVIN: Anne, you're at five and a half minutes. If you could please wrap it up.

MS. HEDGES: Okay -- and it will protect some of our most spectacular locations. I urge you to take the federal land manager's comments into account, as well as EPA's most recent. We will be submitting detailed comments on Monday. Thank you.

MS. DAVIN: Thank you, Anne. Next up we have David Merrill. David, please spell and state your first and last name, and you have three minutes.

MR. MERRILL: My name is David Merrill. D-A-V-I-D M-E-R-R-I-L-L. Thank you for letting me be here today to make this statement.

I'm a senior organizing representative for the Sierra Club working out of Missoula, and I'm speaking on behalf of our over 8,000 members and supporters across Montana. Thank you for this opportunity to address you today.

I was surprised to learn that the Montana Department of Environmental Quality is passing up an opportunity to address Regional Haze, intending to kick the can down the road until 2028. There's no good reason for doing so. For Montanans suffering from respiratory diseases, 2028 would be a very long wait indeed.

You're also letting down the people who come here to enjoy our wide open spaces and thrilling vistas. Outside of wildfire season, a state with a population density as low as Montana should be enjoying some of the cleanest air in the country.

We know that these Regional Haze regulations work. Since the implementation of the Regional Haze Program, the average visual range has increased from 90 to 120 miles in some western parks, and from 50 to 70 miles in some eastern parks.

The bonus is that improving visibility to address the pollution also confers significant public health benefits. The Montana Department of Health and Human Services says there are 94,000 Montanans suffering from asthma. That is over twice the entire population of Bozeman. We do not agree that waiting is an option for them or for any Montanan.

We urge the Department to require stricter pollution controls at the Colstrip Power Plant, the facilities that burn waste coal and petroleum, cement kilns, and oil refineries. It won't happen without you requiring it.

Based upon experiences in other states, we know that there are cost-effective emissions controls that could be implemented immediately. Please do not pass up this opportunity to take another significant step towards the cleaner air we all desire.

MS. PAYNE: Moira, I think you're on mute.

MS. DAVIN: Sorry about that. Thank you, David. Next up is Michelle Uberuaga. You have three minutes. If you could please say and spell your first and last name.

MS. UBERUAGA: Hi. Thank you. My name is Michelle Uberuaga, and it's spelled M-I-C-H-E-L-L-E, last name U-B-E-R-U-A-G-A. Thank you so much for the opportunity to comment today.

I'm commenting on behalf of the Park County Environmental Council. That is a grassroots community organization with more than 3,000 supporters here in Yellowstone's northern gateway. I'm calling from Livingston, Montana.

Here in Park County, our back yard is Yellowstone and wilderness, and these are treasured, these landscapes. They're treasured not only here by locals, but to all Montanans and around the world. We host millions of visitors every year, and those visitors are really important to our local economy.

These are places that we all agree are worth protecting, and of course that's why we have the Clean Air Act, and these places are especially

important to protect from harmful industrial pollution.

That's why I don't think DEQ's plan to do nothing to reduce regional haze for the next ten years is acceptable. It's not acceptable. We can and we must require industrial polluters to pay their fair share. Otherwise Montanans and our children will bear the burden of your decision to do too little, too late.

I'm also a member of an organization called Moms Clean Air Force, which is a community of more than a million caregivers across the country working to protect our children from pollution.

I myself have three young children, and I'm a TF and many, many more. My children spend countless hours exploring our back yard. Our kids deserve clean air, and they're relying on us and you to require industrial polluters to clean up their act. This really cannot wait ten more years. Please rethink your approach for my community and all of our communities. Thank you so much.

MS. DAVIN: Thank you, Michelle. Next up we have Alan Olson. Please say and spell your first and last name, and you have three minutes.

MR. OLSON: Thank you, Moira. My name is Alan Olson, A-L-A-N O-L-S-O-N, and I'm the Executive Director of Montana Petroleum Association.

First off I'd like to really thank the staff at the air bureau there at DEQ. None of this is ever an easy process. We appreciate all of the hard work that the air bureau personnel have put into this rulemaking.

And I'm going to cut her short. We're going to bring in all of our written comments and hand deliver that to you on Monday. But thank you guys very much for all the hard work you've put into this.

MS. DAVIN: Thank you, Alan. Is there anyone else online that wishes to provide public comment? Please raise your hand.

(No response)

MS. DAVIN: And for those who may be unfamiliar with Teams, the raise hand is under the little face with the hand at the top of the screen. Seeing none, is there anyone else in the room who would like to provide comment?

MS. PAYNE: No.

MS. DAVIN: I think you guys are muted, but it looks like there isn't anyone. Okay. With that, thank you everyone for attending the public hearing today. We really appreciate it.

Rhonda, if you could please go to the next slide that includes the information on how to submit comments. Great. So comments are due March 21st, as we mentioned, at 11:59 p.m. They are due to Rhonda, repayne@mt.gov, or you can mail them to our office at M-T-D-E-Q-A-Q-B -- that stands for Air Quality Bureau -- 1520 East Sixth Avenue, Helena, Montana 59620-0901.

Thank you so much for taking the time to be here today and to provide your statements. As a reminder, those statements are due March 21st, and you're welcome to submit those either by email or by mail.

With that, we'll go ahead and conclude the hearing. Thank you so much for attending.

(The proceedings were concluded at 2:24 p.m.)

* * * * *

C E R T I F I C A T E

STATE OF MONTANA)
: SS.
COUNTY OF LEWIS & CLARK)

I, LAURIE CRUTCHER, RPR, Court Reporter, Notary Public in and for the County of Lewis & Clark, State of Montana, do hereby certify:

That the proceedings were taken before me at the time and place herein named; that the proceedings were reported by me in shorthand and transcribed using computer-aided transcription, and that the foregoing - 43 - pages contain a true record of the proceedings to the best of my ability.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my notarial seal this 21st day of March, 2022.

Laurie J Crutcher

LAURIE J. CRUTCHER
NOTARY PUBLIC for the State of Montana
Residing at Helena, Montana
My Commission Expires March 9, 2024

5 - PUBLIC HEARING PARTICIPANTS LIST

Lucy Hochschartner, Gallatin Valley Sunrise, professional athlete, citizen

Evan Romasco-Kelly

America Fitzpatrick, NPCA

Anne Hedges, MEIC

Mark Dihle

Joe Lierow, ExxonMobil – Billings Refinery

Natalie Levine, National Parks Conservation Association

Brian Sullivan, Talen Energy

Alan Olson, Montana Petroleum Association

Brad Sims, ExxonMobil Corporation

Karen Kennah, CHS Inc. – Laurel Refinery

Doug Kuenzli, Ash Grove

Moira Davin, DEQ

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