Appendix H. Public Notice, Comment Letters, and MPCA Response-to-Comments

This appendix contains the public comments received during the public notice of the comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP). The public notice for the comprehensive update to Minnesota's Regional Haze SIP was published in the State Register on August 22, 2022, the public comment period commenced on August 22, 2022, and ended on October 7, 2022. During the public notice period, a copy of the SIP revision was made available at the MPCA office located in St. Paul and on the MPCA's website.

The public notice stated:

> ***Submitting written comments.*** *Comments may be submitted by: (1) Online at https://www.pca.state.mn.us/air/minnesotas-regional-haze-state-implementation-plan (2) By mail to: Maggie Wenger, Minnesota Pollution Control Agency, Environmental Analysis and Outcomes Division, 520 Lafayette Road North, St. Paul, Minnesota 55155-4194; telephone: 651-757-2007 or toll free 1-800-657-3864; fax: 651-297-8324; and email: Maggie.Wenger@state.mn.us. TTY users may call the MPCA at TTY 651-252-5332 or 1-800-657-3864.*
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> ***Public comment period and public meeting.*** *The public comment period begins August 22, 2022, and ends on October 7, 2022. Your comments must be in writing and received by 4:30 p.m. on October 7, 2022. Written comments may be submitted to them at the mailing address or url listed above.*
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> *A public information meeting will be held to provide information, receive public input, and answer questions about the proposed SIP revision. The public meeting will be held on September 22, 2022, from 2:00-4:00 PM at the MPCA St. Paul office and via Microsoft Teams virtual meeting. Information on attending the meeting in person or virtually is available at [http://www.pca.state.mn.us/public-notices.](http://www.pca.state.mn.us/public-notices)*

MPCA received five comment letters prior to the close of the public comment period and two late comment letters regarding this comprehensive SIP revision.

The MPCA's response to the comments received are provided in this Appendix (Response to Comments). The Response to Comments is organized by comment letter in the order they were received. The comments are summarized and not typically presented verbatim. The comments on specific sections or topics are organized by those sections or topics. Each section is followed by a list of the comments submitted related to the section, and MPCA's response.

The MPCA's Response to Comments includes references to documents issued by U.S. EPA, specifically the guidance issued on August 20, 2019 (August 2019 Guidance), and a clarification memorandum issued on July 8, 2021 (July 2021 Clarification Memo).[1,2]

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[1] *See* U.S. EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period 55 (Aug. 2019), *https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf* [hereinafter Aug. 2019 EPA Guidance].

[2] *See* U.S. EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021), *https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf* [hereinafter July 2021 EPA Clarifications*].*

List of interested Parties

The following is a list of interested parties who submitted written comments on the proposed rules during the public notice comment period from August 22, 2022, through October 7, 2022.

1. Comments submitted by Christine Goepfert, National Parks Conservation Association (NPCA), posted on MPCA's SmartComment software at 3:17 p.m. on September 22, 2022, with attached comment letter.
2. Comments from Herbert Frost, National Park Service - Interior Region 3, 4, 5 (U.S. NPS), posted on MPCA's SmartComment software at 12:41 p.m. on October 4, 2022, with attached comment letter.
3. Comments submitted by Julia Guerrein, Minnesota Land and Manoomin Protection Project Fellowship Team with Public Lab, posted on MPCA's SmartComment software at 7:58 p.m. on October 5, 2022.
4. Comments submitted by Sagar Sunkavalli, Southern Minnesota Beet Sugar Cooperative (SMBSC), posted on MPCA's SmartComment software at 2:47 p.m. on October 7, 2022, with attached comment letter.
5. Comments submitted by Jason Aagenes, Cleveland-Cliffs Inc. (Cliffs), via email at 4:15 p.m. on October 7, 2022, with attached comment letter.
6. Comments submitted by Pamela Blakely, United States Environmental Protection Agency - Region 5 (U.S. EPA Region 5), posted on MPCA's SmartComment software at 7:01 p.m. on October 7, 2022, with attached comment letter.
7. Comments submitted by Sara Laumann, Laumann Legal LLC, for the Coalition to Protect America's National Parks (Coalition), Environmental Law and Policy Center (ELPC), Minnesota Center for Environmental Advocacy (MCEA), National Parks Conservation Association (NPCA), and Sierra Club posted on MPCA's SmartComment software at 8:18 p.m. on October 7, 2022, with attached comment letter.

Comment letter 1 - National Parks Conservation Association (NPCA)

Comment 1. The commenter commended MPCA for proposing a technically sound regional haze plan for this planning period. The MPCA had a robust source selection process, a strong commitment to working with the National Park Service and other federal land managers throughout the consultation process, rejected international endpoint adjustments, and used a good initial screening cost threshold (comment letter page 1).

Response: Comment noted.

Comment 2. The commenter requested that MPCA should evaluate and require pollution control improvements at all the taconite facilities initially selected. The commenter stated that these facilities emit more than 70% of the total haze emissions from Minnesota and not only impact Voyageurs and the Boundary Waters, but other Federal Class I areas (Class I areas) in neighboring states. The commenter continued that the taconite facilities are located close to Hibbing, Chisholm, Virginia and Mount Iron, among other communities, that are negatively impacted by pollution from the mining processes at the taconite facilities and MPCA must consider environmental justice factors, which substantiate the need for sharp reductions in the state's haze plan (comment letter page 1).

Response: See MPCA's responses to Comment 99 and Comment 112 through Comment 118.

Comment 3. The commenter requested that MPCA require cost-effective controls for the sugar beet processing and paper manufacturing facilities for which the costs were overestimated in the draft SIP. The commenter stated that the National Park Service also recommended this, and they wholly support this action (comment letter page 2).

Response: See MPCA's responses to Comment 111.

Comment letter 2 - National Parks Service (U.S. NPS)

Comment 4. The commenter commended MPCA for a robust source selection process, commitment to working with NPS and other FLMs throughout the consultation process, rejection of international endpoint adjustments, and the use of a $10k initial screening cost threshold for controls. The commenter also state that the Minnesota draft Regional Haze SIP is one of the most technically sound and complete plans that the U.S. NPS has reviewed in this planning period (cover letter page 1; comment letter page 2, section 1).

Response: Comment noted.

Comment 5. The commenter stated that the public notice announcing the availability of the draft SIP did not include a summary of the conclusions and recommendations of the Federal Land Managers as required by 42 U.S.C. § 7491 (cover letter page 1).

Response: The MPCA included a summary of the conclusions and recommendations of the FLMs in the public notice materials in a GovDelivery email to the Regional Haze email list. Additionally, a summary of the FLM conclusions and recommendations was available in Section 4.3 of the draft Regional Haze SIP and a full copy of conclusions and recommendations from the FLMs is included in Appendix G. Consultation Comments.

Comment 6. The commenter stated that based on their analysis of emissions relative to distance to NPS Class I areas, Minnesota ranked 9th in visibility impairing emissions within the U.S., with the taconite facilities comprising more than half of those impacts. The commenter added that their analysis in technical documents, attached to their letter, demonstrate there are more effective controls available that may be technically feasible and cost-effective (cover letter page 1; comment letter page 2, section 1).

Response: The MPCA addresses the comments related to taconite facilities later in this document. See MPCA's responses to Comment 44 through Comment 51.

Comment 7. The commenter stated they found emissions controls that may be cost effective for American Crystal Sugar (ACS) Crookston, ACS East Grand Forks, Southern Minnesota Beet Sugar Cooperative, and Power Boiler 9 at the Sappi Cloquet paper mill based on revisions to their technical analyses, reflected in attachments to their letter. Specifically, the commenter adjusted cost estimates based on the parameters used by MPCA in the latest draft of the SIP. The commenter recommended that cost-effective emission controls be required for these facilities (cover letter page 1-2; comment letter page 2, section 1).

Response: The MPCA addresses the comments related to taconite facilities later in this document. See MPCA's response to Comment 18 through Comment 22 regarding American Crystal Sugar - Crookston, Comment 23 through Comment 27 regarding American Crystal Sugar - East Grand Forks, Comment 28 through Comment 33 regarding Southern Minnesota Beet Sugar Cooperative, and Comment 34 through Comment 37 regarding Sappi Cloquet.

Comment 8. The commenter indicated that they adjusted some previous feedback they provided on the pre-public notice Regional Haze SIP to reflect significant differences involving control cost estimates. Since 2019, the Chemical Engineering Plant Cost Index (CEPCI) has risen from 607.5 to 708.0 and the prime interest rate has risen from 3.25% to 5.5%. Instead of continuing to use these recent values in cost estimates, the commenter revised the estimates previously provided to be consistent with the values used by MPCA—namely CEPCI of 607.5 and a 3.5% interest rate reflective of 2019 values. Following is a discussion of some overarching issues as well as how the revised NPS control cost estimates differ from those presented by MPCA (comment letter page 2, section 2).

Response: The MPCA believes the commenter provided these details as background information to support their comments. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 9. The commenter provided comments regarding the four-factor analysis screening done via a demonstration of effective controls. The commenter stated that they found that, for many of the sources that MPCA determined were effectively controlled for this implementation period, a 4-factor analysis may have resulted in additional controls. See the comments on individual facilities for specific information (comment letter page 3, section 2.1).

Response: In general, MPCA's decision to remove certain emission sources from further analysis in the four-factor analysis process is documented in Section 2.3.5 of Minnesota's Regional Haze SIP and relies on U.S. EPA's August 2019 Guidance. In this section, MPCA provides information to support its conclusion, specific to each emission source. After site specific review, it was found that these emission sources were effectively controlled and further analysis under the four-factor analysis process was not necessary.

MPCA addresses the comments regarding the effectively controlled determinations for individual facilities later in this document. Specifically, the commenter raises concerns regarding effectively controlled determinations for Boise White Paper's Boiler #2 and indurating furnaces at taconite iron ore processing facilities in Minnesota. See MPCA's response to Comment 38 regarding effectively controlled determination for Boise White Paper and MPCA's responses to Comment 44 regarding effectively controlled determinations for Minnesota taconite facilities.

Comment 10. The commenter provided comments regarding retrofit factors used in cost analyses and where the value differed between the commenter's analyses and MPCA's analyses. The commenter stated that most of the facilities and MPCA provided inadequate documentation to justify application of the various retrofit factors, identified the retrofit factor used in the draft Regional Haze SIP, and provided an alternative retrofit factor used in the commenter's analyses (comment letter page 3-4, section 2.2).

Response: Regarding the retrofit factor used for various facilities, MPCA disagrees with the commenter. During MPCA's review of the four-factor analyses, MPCA requested that all facilities justify the choice of retrofit factor, and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 11. The commenter provided comments regarding control efficiencies and outlet emissions for specific control technologies. The commenter provided a summary of the values for control efficiencies and outlet emissions for their cost analyses and where they believe MPCA underestimated the control efficiency of certain control strategies, including dry sorbent injection (DSI) (comment letter page 4, section 2.3).

Response: The MPCA believes the commenter provided the details of how they determined control efficiency for various emission control technologies as background information to support comments made later in their letter. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Regarding the commenter's statement that they believe MPCA underestimated the control efficiency of dry sorbent injection (DSI), MPCA disagrees with the commenter. The U.S. EPA's Control Cost Manual, Section 5 states that DSI as an SO_2 control measure can typically achieve SO_2 control efficiencies ranging from 50% to 70% and references their use in power plants, biomass boilers, and industrial applications.[3] While there are other sources that may suggest different control efficiencies, MPCA believes it has reasonably estimated the control efficiency that potential applications of DSI could achieve.

Comment 12. The commenter provided comments on control equipment lifespans. The commenter identified recommended equipment lifespans contained in U.S. EPA's Control Cost Manual for industrial boilers. The commenter then provided a summary comparison of the equipment lifespan used in their analyses versus MPCA analyses (comment letter page 4-5, section 2.4).

Response: The MPCA believes the commenter provided the details of how they determined equipment life for various emission control technologies as background information to support comments made later in their letter. The MPCA addresses the comments that use these details throughout the responses to this commenter.

In general, MPCA believes it has reasonably estimated control equipment lifespans for the potential control measures based on information available in the U.S. EPA's Control Cost Manual. The MPCA verified that the values used in the analyses were within the range of typical values that the U.S. EPA identifies.

Comment 13. The commenter provided comments regarding unsupported cost estimates, stating that in at least one instance, MPCA relied on vendor quotes that were unavailable to the commenter. The commenter continued that MPCA included costs that were unjustified (e.g., demolitions, ESP replacements, and stack replacements) and did not account for avoided operating costs (e.g., ESP removal) (comment letter page 5, section 2.5).

Response: The vendor quotes that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

The MPCA believes the commenter provided these comments as a high-level summary to support more detailed comments made later in their letter. The MPCA addresses the comments that use these details throughout the responses to this commenter.

In general, MPCA believes it has reasonably estimated costs for potential control measures based on information available in the U.S. EPA's Control Cost Manual. As stated in Section 2.4.3 of the draft Regional Haze SIP, MPCA reviewed the facility-provided cost estimates, comments provided by FLMs, U.S. EPA, and Tribes, and revised cost estimates to address certain parameters in the facility-provided cost estimates.

Comment 14. The commenter provided comments surrounding missing and incomplete analyses and unsupported control determinations. The commenter stated that MPCA did not discuss Selective Catalytic Reduction (SCR) at American Crystal Sugar's Crookston and East Grand Forks plants in its final

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[3] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS, *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution* (last visited June 23, 2022) [hereinafter COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS].

draft, but MPCA included evaluations of SCR on all five boilers in Appendix E. The commenter also stated that there were control strategies identified by MPCA below the $7,600/ton threshold for Southern Minnesota Beet Sugar (i.e., SCR) and Boise White Paper (i.e., SNCR) that weren't selected and no explanation was provided for that decision (comment letter page 5, section 2.6).

Response: The MPCA disagrees with the commenter's statement that MPCA did not discuss SCR for the American Crystal Sugar - Crookston and American Crystal Sugar - East Grand Forks facilities in the draft Regional Haze SIP. The MPCA considered and identified both SNCR and SCR controls for the American Crystal Sugar facilities in Section 2.4 of the draft Regional Haze SIP. As documented in Section 2.5.1, MPCA used a $10,000 per ton initial screening threshold to determine which control measures to focus on in the review of four-factor analyses. Application of SCR on the boilers at these facilities was near or above the initial screening threshold, depending on if the cost estimate was the facility-prepared or MPCA-revised version, so the control measure did not carry through to later parts of the analysis.

Furthermore, while the commenter is correct that there are some control measures that are below a $7,600 per ton cost-effectiveness value, Section 2.5.1 also identifies that MPCA did not use a specific cost-threshold to uniformly determine whether a control measure was cost-effective or not. Rephrased, $7,600 per ton is not a threshold used or selected by MPCA. The MPCA used a singular threshold of $10,000 per ton for the purpose of initially screening control measures for cost-effectiveness. After the initial screening, MPCA reviewed all control measures and found that among the potentially cost-effective control measures, the most expensive measure MPCA pursued was approximately $7,600 per ton. The MPCA would also like to reiterate that these cost-effectiveness "thresholds" were identified and specifically called out in the draft Regional Haze SIP in response to a request to do so from U.S. EPA on a pre-public notice version of the draft Regional Haze SIP.

Comment 15. The commenter provided comments surrounding cost effectiveness thresholds and the sources of information used in developing a cost-effectiveness threshold. The commenter asked if MPCA adjusted these costs for inflation and if MPCA made control determinations based upon a derived cost-effectiveness threshold ($7,600/ton in 2019 dollars) or if the threshold was the result of a subjective determination of what constitutes a reasonable control strategy. The commenter asked if MPCA is basing its determinations on the $7,600/ton threshold, and recommended MPCA show how that value was derived. Otherwise, the commenter stated that MPCA should provide a clearer explanation of how it arrived at a $7,600/ton threshold (comment letter page 5-7, section 2.7).

Response: Regarding the analysis of control costs from the first regional haze implementation period, MPCA would like to reiterate that these values were not used to determine whether a control measure in this implementation period was considered cost-effective. The MPCA established a cost-effectiveness threshold of $10,000 for initial screening purposes only. The MPCA used information from the first regional haze implementation period, as well as cost-effectiveness data from other states' Regional Haze SIP and the U.S. EPA's RBLC, for comparison to the costs of control measures evaluated in a four factor analysis. Additionally in the draft Regional Haze SIP, MPCA identifies that U.S. EPA's August 2019 Guidance provides this concept as a recommendation for states to use when evaluating the cost of compliance for potential control measures.[4]

The MPCA did adjust these costs for inflation by scaling the cost data to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). The MPCA revised Section 2.5.1 of the draft Regional Haze SIP to clarify that the cost data evaluated in U.S. EPA's RBLC was scaled to 2019 dollars.

[4] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 37-40.

Regarding the $7,600 per ton value, MPCA revised Section 2.5.1 of the draft Regional Haze SIP to clarify that MPCA did not choose $7,600 per ton as a threshold to determine which control measures would be recommended. Rather, there are a range of cost-effective control measures identified by MPCA, with the most expensive measure MPCA pursued was approximately $7,600 per ton.

Comment 16. The commenter provided comments regarding the determination that SNCR would be cost-effective for three boilers at Hibbing Public Utilities Commission. The commenter disagreed with MPCA's approach to establish NO_X emission limits, that would provide equivalent reductions to installing SNCR controls on these boilers, instead of requiring SNCR controls. The commenter recommended that MPCA require installation of SNCR for NO_X emission reductions (comment letter page 7, section 3.1).

Response: The MPCA proposed the strategy because the expected future operations of the boilers were expected to differ from historical operating practices. The proposed NO_X emission limits provided the equivalent level of control, to the controls determined to be cost-effective under historical operating practices, while accommodating the facility's proposed changes to operating practices moving forward.

Comment 17. The commenter provided comments regarding the Minnesota Power - Boswell Energy Center facility and the actual SO_2 emission rates for Units 3 and 4 compared to the allowable SO_2 emission rate. The commenter recommended that MPCA establish lower SO_2 emission rates closer to the actual emission rates to prevent backsliding and ensure that emission rates remain low (comment letter page 7, section 3.2).

Response: As identified in Section 2.3.5 of the draft Regional Haze SIP, the NO_X and SO_2 emission controls and associated limits are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis, an emission unit that went through a BACT review, and/or EGUs with add-on FGD that meet the applicable SO_2 limits of the MATS rule).[5]

The information provided in Section 2.3.5 of the draft Regional Haze SIP regarding recent emission levels for Units 3 and 4 was included to address Section 4.1 of the U.S. EPA July 2021 Clarification Memo, which suggested states should include information on a source's past performance to determine when existing measures are necessary for reasonable progress. The memo states that this information may be helpful to inform the expected future operations of the source (i.e., consistent historical operations suggests that future operations will also be consistent) alongside the existence of enforceable requirements that reflect the source's existing measures. Based on the information provided in Section 2.3.5, MPCA stated that these sources with effective controls do not require additional measures to continue making reasonable progress, as described in Section 2.5.6 of the draft Regional Haze SIP. Therefore, MPCA did not require four-factor analyses for these units nor establish recent SO_2 emission rates as new enforceable limits.

Comment 18. The commenter provided recommendations for the American Crystal Sugar - Crookston facility based on their cost analyses that show the cost of control is more economical than estimated by MPCA. The commenter stated that the addition of dry sorbent injection (DSI), with or without replacing the existing electrostatic precipitators (ESPs) with fabric filters, would be below the $7,600/ton cost threshold.

The commenter stated that although MPCA did not discuss Selective Catalytic Reduction (SCR), but MPCA included evaluations of SCR on all three boilers in Appendix E. The commenter provided

[5] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.

comments regarding assumptions used in those evaluations for equipment lifespan and control efficiency.

Overall, the commenter recommended that MPCA require the facility to implement DSI with a new baghouse as well as SCR on the three boilers at the facility (comment letter page 8-9, section 4.1.1).

Response: MPCA appreciates the detailed review and comments provided on the cost estimates from the facility and the revisions made to those estimates by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has reasonably estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.

The MPCA disagrees with the commenter's statement that MPCA did not discuss SCR for this facility, see MPCA's response to Comment 14. Regarding the $7,600 per ton value, see MPCA's response to Comment 14 as well.

Comment 19. The commenter provided a narrative summary regarding facility characteristics, specifically the emission units of interest, existing control equipment, maximum rated heat input, fuel characteristics, distance to Voyageurs National Park, and the 2017 national emissions inventory summary of plantwide NO_X and SO_2 emissions (comment letter page 9, section 4.1.2).

Response: The MPCA provided similar information in the draft Regional Haze SIP in Section 2.3.2 (distance to Minnesota Class I areas) and Section 2.4.2 (maximum rated heat input and emissions data). The MPCA believes the commenter provided these details as background information to support their comments. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 20. The commenter provided comments and recommendations surrounding the SO_2 four-factor analysis for the American Crystal Sugar - Crookston facility. The commenter supported the selection of control equipment evaluated. The commenter disagreed with the facility's consultant, who determined that the addition of DSI, with existing ESPs, would potentially result in non-compliance with particulate or mercury limits without a polishing baghouse. The commenter also disagreed with the values used for equipment lifespan, control efficiency, SO_2 emission rate, and retrofit factor in the cost evaluations. The commenter provided their own analysis of SO_2 control costs using the four statutory factors to evaluate SO_2 control strategies (comment letter page 9-13, section 4.1.3).

Response: The MPCA disagrees with the commenter that the facility did not provide enough technical basis to support their analysis that a polishing baghouse would be needed to achieve additional SO_2 control without jeopardizing compliance with existing PM limits. As the facility states in their February 2, 2022, supplement (included in Appendix B. Four-Factor Analyses - Facility Responses), the percent control efficiency achievable was based on site-specific considerations, included in the supplement, that impact the performance of the existing ESPs or the potential application of DSI.

Regarding equipment lifespan and control efficiency, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[6] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

[6] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*

Regarding the SO_2 emission rate, MPCA acknowledges that there are inconsistencies in the annual emissions reported by the facility versus annual emissions calculations using the emission unit's rate heat input capacity and lb/MMBtu emission rate. The MPCA reviewed these inconsistencies and specifically address them in Section 2.4.2 of the draft Regional Haze SIP.

Regarding the retrofit factor value, MPCA disagrees with the commenter. During MPCA's review of the four-factor analyses, MPCA requested that all facilities justify the choice of retrofit factor and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 21. The commenter provided comments and recommendations surrounding the NO_X four-factor analysis for the American Crystal Sugar - Crookston facility. The commenter disagreed with the controlled emission rates presented for Selective Catalytic Reduction (SCR). The commenter also disagreed with the values used for equipment lifespan, control efficiency, NO_X emission rate, and retrofit factor in the cost evaluations. The commenter provided their own analysis of NO_X control costs using the four statutory factors to evaluate NO_X control strategies (comment letter page 13-16, section 4.1.4).

Response: Regarding equipment lifespan, SCR controlled emission rate, and SCR control efficiency, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[7] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

Regarding the NO_X emission rate, MPCA acknowledges that there are inconsistencies in the annual emissions reported by the facility versus annual emissions calculations using the emission unit's rate heat input capacity and lb/MMBtu emission rate. The MPCA reviewed these inconsistencies and specifically address them in Section 2.4.2 of the draft Regional Haze SIP.

Regarding the retrofit factor value, MPCA disagrees with the commenter. During MPCA's review of the four-factor analyses, MPCA requested that all facilities justify the choice of retrofit factor and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 22. The commenter provided a summary of their conclusions and recommendations for the American Crystal Sugar - Crookston facility. The commenter stated that MPCA has overestimated the cost of compliance in the four factor analyses and based on their own analyses recommends that MPCA require the implementation of NO_X and SO_2 control strategies on the three boilers at the facility (comment letter page 16, section 4.1.5).

Response: The MPCA appreciates the comments made. This comment is a summary of the commenters other comments, which are addressed in Comment 18 through Comment 21. See MPCA's response to Comment 18 through Comment 21.

Comment 23. The commenter provided recommendations for the American Crystal Sugar - East Grand Forks facility based on the commenter's cost analyses that show the cost of control is more economical than estimated by MPCA. The commenter stated that addition of dry sorbent injection (DSI), with or without replacing the existing electrostatic precipitators (ESPs) with fabric filters, would be below the $7,600/ton cost threshold.

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[7] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*

The commenter stated that although MPCA did not discuss Selective Catalytic Reduction (SCR), but MPCA included evaluations of SCR on both boilers in Appendix E. The commenter provided comments regarding assumptions used in those evaluations for equipment lifespan and control efficiency.

Overall, the commenter recommended that MPCA require the facility to implement DSI with a new baghouse as well as SCR on both boilers at the facility (comment letter page 17, section 4.2.1).

Response: MPCA appreciates the detailed review and comments provided on the cost estimates from the facility and the revisions made to those estimates by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has reasonably estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.

The MPCA disagrees with the commenter's statement that MPCA did not discuss SCR for this facility, see MPCA's response to Comment 14. Regarding the $7,600 per ton value, see MPCA's response to Comment 14 as well.

Comment 24. The commenter provided a narrative summary regarding facility characteristics, specifically the emission units of interest, existing control equipment, maximum rated heat input, fuel characteristics, distance to Voyageurs National Park, and the 2017 national emissions inventory summary of plantwide NO_X and SO_2 emissions (comment letter page 17-18, section 4.2.2).

Response: The MPCA provided similar information in the draft Regional Haze SIP in Section 2.3.2 (distance to Minnesota Class I areas) and Section 2.4.2 (maximum rated heat input and emissions data). The MPCA believes the commenter provided these details as background information to support their comments. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 25. The commenter provided comments and recommendations surrounding the SO_2 four-factor analysis for the American Crystal Sugar - East Grand Forks facility. The commenter supported the selection of control equipment evaluated. The commenter disagreed with the facility's consultant, who determined that the addition of DSI, with existing ESPs, would result in non-compliance with particulate or mercury limits without a polishing baghouse. The commenter also disagreed with the values used for equipment lifespan, control efficiency, SO_2 emission rate, and retrofit factor in the cost evaluations. The commenter provided their own analysis of SO_2 control costs using the four statutory factors to evaluate SO_2 control strategies (comment letter page 18-21, section 4.2.3).

Response: The MPCA disagrees with the commenter that the facility did not provide enough technical basis to support their analysis that a polishing baghouse would be needed to achieve additional SO_2 control without jeopardizing compliance with existing PM limits. As the facility states in their February 2, 2022, supplement (included in Appendix B. Four-Factor Analyses - Facility Responses), the percent control efficiency achievable was based on site-specific considerations, included in the supplement, that impact the performance of the existing ESPs or the potential application of DSI.

Regarding equipment lifespan and control efficiency, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[8] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

[8] *See* U.S. EPA, Cost Reports and Guidance for Air Pollution Regulations*, supra.*

Regarding the SO_2 emission rate, MPCA acknowledges that there are inconsistencies in the annual emissions reported by the facility versus annual emissions calculations using the emission unit's rate heat input capacity and lb/MMBtu emission rate. The MPCA reviewed these inconsistencies and specifically address them in Section 2.4.2 of the draft Regional Haze SIP.

Regarding the retrofit factor value, MPCA disagrees with the commenter. During MPCA's review of the four-factor analysis, MPCA requested that all facilities justify the choice of retrofit factor, and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 26. The commenter provided comments and recommendations surrounding the NO_X four-factor analysis for the American Crystal Sugar - East Grand Forks facility. The commenter disagreed with the controlled emission rates presented for Selective Catalytic Reduction (SCR). The commenter also disagreed with the values used for equipment lifespan, control efficiency, NO_X emission rate, and retrofit factor in the cost evaluations. The commenter provided their own analysis of NO_X control costs using the four statutory factors to evaluate NO_X control strategies (comment letter page 21-23, section 4.2.4).

Response: Regarding equipment lifespan, SCR controlled emission rate, and SCR control efficiency, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[9] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

Regarding the NO_X emission rate, MPCA acknowledges that there are inconsistencies in the annual emissions reported by the facility versus annual emissions calculations using the emission unit's rated heat input capacity and lb/MMBtu emission rate. The MPCA reviewed these inconsistencies and specifically address them in Section 2.4.2 of the draft Regional Haze SIP.

Regarding the retrofit factor value, MPCA disagrees with the commenter. During MPCA's review of the four-factor analysis, MPCA requested that all facilities justify the choice of retrofit factor, and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 27. The commenter provided a summary of their conclusions and recommendations for the American Crystal Sugar - East Grand Forks facility. The commenter stated that MPCA has overestimated the cost of compliance in the four factor analyses and based on their own analysis recommends that MPCA require the implementation of NO_X and SO_2 control strategies on the three boilers at the facility (comment letter page 23, section 4.2.5).

Response: The MPCA appreciates the comments made. This comment is a summary of the commenters other comments, which are addressed in Comment 23 through Comment 26. See MPCA's response to Comment 23 through Comment 26.

Comment 28. The commenter provided recommendations for the Southern Minnesota Beet Sugar Cooperative facility based on their cost analysis that show the cost of control is more economical than estimated by MPCA. The commenter stated that addition of the Spray Dry Absorber/Circulating Dry Scrubber (SDA/CDS) option and Selective Catalytic Reduction (SCR), would be below the $7,600/ton cost threshold.

[9] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS, *supra*.

Overall, the commenter recommended that MPCA require the facility to implement SDA/CDS and SCR on Boiler 1 at the facility (comment letter page 24, section 4.3.1).

Response: MPCA appreciates the detailed review and comments provided on the cost estimates from the facility and the revisions made to those estimates by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has reasonably estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.

Regarding specific controls identified below a $7,600 per ton cost-effectiveness, see MPCA's response to Comment 14. Regarding the $7,600 per ton value, see MPCA's response to Comment 14 as well.

Comment 29. The commenter provided a narrative summary regarding facility characteristics, specifically the emission units of interest, existing control equipment, maximum rated heat input, fuel characteristics, and distance to Voyageurs National Park (comment letter page 24, section 4.3.2).

Response: The MPCA provided similar information in the draft Regional Haze SIP in Section 2.3.2 (distance to Minnesota Class I areas) and Section 2.4.2 (maximum rated heat input and emissions data). The MPCA believes the commenter provided these details as background information to support their comments. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 30. The commenter provided comments regarding values used for reagent, electricity, and labor costs in the four factor analyses. The commenter stated that the facility and MPCA increased these values above default values and instead should be based on site-specific costs or defaults identified in U.S. EPA's Control Cost Manual (comment letter page 25, section 4.3.3).

Response: The MPCA disagrees with the commenter's characterization of the values MPCA used to estimate costs of various emission control technologies. The MPCA either revised the cost estimates prepared by the facility to use default reagent costs and electricity costs based on information available from the U.S. Energy Information Administration (Electric Power, January 2022 for MN industrial users). While MPCA did not do the same for labor costs, these costs represent a small fraction of the total annual cost estimated via the U.S. EPA control cost manual spreadsheets and revising them would not have resulted in a different conclusion. For example, in the cost estimate for SCR, operator costs inform the indirect annual cost value through "Administrative Charges" that work out to be $4,790 per year compared to the total annual cost of $3,565,566 per year, or 0.13% of the total annual cost.

Comment 31. The commenter provided comments and recommendations surrounding the SO_2 four-factor analysis for the Southern Minnesota Beet Sugar Cooperative facility. The commenter disagreed with the facility's consultant, who determined that the addition of DSI, with existing ESPs, would result in non-compliance with particulate matter limits without a polishing baghouse. The commenter also disagreed with the values used for equipment lifespan, control efficiency, and retrofit factor in the cost evaluations. The commenter provided their own analysis of SO_2 control costs using the four statutory factors to evaluate SO_2 control strategies (comment letter page 25-29, section 4.3.4).

Response: The MPCA disagrees with the commenter that the facility did not provide enough technical basis to support their analysis that a polishing baghouse would be needed to achieve additional SO_2 control without jeopardizing compliance with existing PM limits. As the facility states in their four-factor analysis, the percent control efficiency achievable was based on site-specific considerations, included in their four-factor analysis, that impact the performance of the existing ESPs or the potential application of DSI.

Regarding equipment lifespan and control efficiency, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[10] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

Regarding the retrofit factor value, MPCA disagrees with the commenter. During MPCA's review of the four-factor analysis, MPCA requested that all facilities justify the choice of retrofit factor and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 32. The commenter provided comments and recommendations surrounding the NO_X four-factor analysis for the Southern Minnesota Beet Sugar Cooperative facility. The commenter disagreed with the controlled emission rates presented for Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). The commenter also disagreed with the values used for equipment/catalyst lifespan, control efficiency, and retrofit factor in the cost evaluations. The commenter provided their own analysis of NO_X control costs using the four statutory factors to evaluate NO_X control strategies (comment letter page 29-34, section 4.3.5).

Response: Regarding equipment/catalyst lifespan, controlled SNCR/SCR emission rate, and SNCR/SCR control efficiency, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[11] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

Regarding the retrofit factor value, MPCA disagrees with the commenter. During MPCA's review of the four-factor analysis, MPCA requested that all facilities justify the choice of retrofit factor and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 33. The commenter provided a summary of their conclusions and recommendations for the Southern Minnesota Beet Sugar Cooperative facility. The commenter stated that MPCA has overestimated the cost of compliance in the four factor analysis, and based on their own analysis recommends that MPCA require the implementation of NO_X and SO_2 control strategies on Boiler 1 at the facility (comment letter page 34-35, section 4.3.6).

Response: The MPCA appreciates the comments made. This comment is a summary of the commenters other comments, which are addressed in Comment 28 through Comment 32. See MPCA's response to Comment 28 through Comment 32.

Comment 34. The commenter provided recommendations for the Sappi Cloquet facility based on their cost analysis that show the cost of control is more economical than estimated by MPCA for Power Boiler #9. The commenter agreed with MPCA's determination that Recovery Boiler #10 is effectively controlled for this implementation period and can be screened from the four-factor evaluation. Overall, the

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[10] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*
[11] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*

commenter recommended that MPCA require the facility to implement Selective Catalytic Reduction (SCR) on Power Boiler #9 at the facility (comment letter page 36, section 5.1.1).

Response: The MPCA appreciates the detailed review and comments provided on the cost estimates from the facility and the revisions made to those estimates by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has reasonably estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.

Comment 35. The commenter provided a narrative summary regarding facility characteristics, specifically the emission units of interest, existing control equipment, distance to Voyageurs National Park, and the 2016 NO_X emissions reported from the emission units of interest (comment letter page 36-37, section 5.1.2).

Response: The MPCA provided similar information in the draft Regional Haze SIP in Section 2.3.2 (distance to Minnesota Class I areas) and Section 2.4.2 (maximum rated heat input and emissions data). The MPCA believes the commenter provided these details as background information to support their comments. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 36. The commenter provided comments and recommendations surrounding the NO_X four-factor analysis for the Sappi Cloquet facility. The commenter supported the selection of control equipment evaluated. The commenter disagreed with the controlled emission rates presented for Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). The commenter also disagreed with the values used for retrofit factors in the cost evaluations. The commenter provided their own analysis of NO_X control costs using the four statutory factors to evaluate NO_X control strategies (comment letter page 37-39, section 5.1.3).

Response: Regarding the SNCR/SCR controlled emission rate, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[12] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

Regarding the retrofit factor value, MPCA disagrees with the commenter. During MPCA's review of the four-factor analyses, MPCA requested that all facilities justify the choice of retrofit factor, and provided facilities the FLM comments that noted the same need to justify the retrofit factor used. The justifications that the facilities provided as part of their four-factor analyses are included in Appendix B. Four-Factor Analyses - Facility Responses.

Comment 37. The commenter provided a summary of their conclusions and recommendations for the Sappi Cloquet facility. The commenter stated that they agreed with MPCA's determinations that Recovery Boiler #10 is effectively controlled for this implementation period and can be screened from the four-factor evaluation, and that projected SO_2 emissions from Power Boiler #9 are too low to warrant evaluation of SO_2 controls; and recommended that MPCA require the implementation of NO_X control strategies on Power Boiler #9 at the facility (comment letter page 39-40, section 5.1.4).

[12] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS, *supra.*

Response: The MPCA appreciates the comments made. This comment is a summary of the commenters other comments, which are addressed in Comment 34 through Comment 36. See MPCA's response to Comment 34 through Comment 36.

Comment 38. The commenter provided recommendations for the Boise White Paper facility based on their cost analysis that show the cost of control is more economical than estimated by MPCA. The commenter disagreed with MPCA's determination that Boiler 2 and the Recovery Furnace are effectively controlled for this implementation period and can be screened from the four-factor evaluation and recommended that MPCA require a four-factor evaluation of NO_X control strategies for these emission units. The commenter also recommended that MPCA adjust the permitted NO_X emission rate of Boiler 1 to more closely reflect the emission rate evaluated (comment letter page 40, section 5.2.1).

Response: The MPCA added additional details to the Regional Haze SIP regarding the effectively controlled determination for this facility. These additions were made to Section 2.3.5 in response to the U.S. NPS consultation comments on the pre-public notice version of the draft Regional Haze SIP, and include a comparison of reported emissions data for recent years to support effectively controlled determinations. The additional information shows that the facility has been implementing the existing controls and achieving a consistent emission rate over the last five years.

As identified in Section 2.3.5 of the draft Regional Haze SIP, the NO_X and SO_2 emission controls and associated limits are similar to examples, identified by the U.S. EPA in its August 2019 Guidance, where it may be reasonable to not select a source for further analysis (i.e., an emission unit that went through a BACT review).[13]

The information provided in Section 2.3.5 of the draft Regional Haze SIP regarding recent emission levels for Boiler 2 and the Recovery Furnace was to address Section 4.1 of the U.S. EPA July 2021 Clarification Memo, which suggested states should include information on a source's past performance to determine when existing measures are necessary for reasonable progress. The memo states that this information may be helpful to inform the expected future operations of the source (i.e., consistent historical operations suggests that future operations will also be consistent) alongside the existence of enforceable requirements that reflect the source's existing measures. Based on the information provided in Section 2.3.5, MPCA stated that these sources with effective controls do not require additional measures to continue making reasonable progress, as described in Section 2.5.6 of the draft Regional Haze SIP. Therefore, MPCA did not require four-factor analyses for these units nor establish recent NO_X emission rates as new enforceable limits.

Regarding the NO_X emission rates used in the four-factor analysis for Boiler 1, MPCA believes it has adequately estimated the potential cost of controls while accounting for the expected emission rate of Boiler 1 by using the actual emissions rate instead of a potential emissions rate.

Comment 39. The commenter provided a narrative summary regarding facility characteristics, specifically the emission units of interest, existing control equipment, distance to Voyageurs National Park, and the 2016 NO_X emissions reported from the emission units of interest (comment letter page 40, section 5.2.2).

Response: The MPCA provided similar information in the draft Regional Haze SIP in Section 2.3.2 (distance to Minnesota Class I areas) and Section 2.4.2 (maximum rated heat input and emissions data). The MPCA believes the commenter provided these details as background information to support their

[13] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.

comments. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 40. The commenter provided comments and recommendations surrounding the NO_X four-factor analysis for Boiler 1 at the Boise White Paper facility. The commenter disagreed with the values used for equipment life in the cost evaluations. The commenter provided their own analysis of NO_X control costs using the four statutory factors to evaluate NO_X control strategies (comment letter page 40-42, section 5.2.3).

Response: Regarding equipment lifespan, MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[14] The MPCA verified that the values used in the analysis were within the range of typical values that the U.S. EPA identifies.

Comment 41. The commenter provided comments and recommendations surrounding a NO_X four-factor analysis for Boiler 2 at the Boise White Paper facility. The commenter disagreed with MPCA's effectively controlled determination for this emission unit. The commenter then provides their own analysis of NO_X control costs using the four statutory factors to evaluate NO_X control strategies (comment letter page 42-44, section 5.2.4).

Response: See MPCA's response to Comment 38 regarding effectively controlled determination for this emission unit.

Comment 42. The commenter provided comments and recommendations surrounding a NO_X four-factor analysis for the Recovery Furnace at the Boise White Paper facility. The commenter disagreed with MPCA's effectively controlled determination for this emission unit and recommended that MPCA investigate the addition of quaternary air, alongside staged air combustion, if it is not already in use (comment letter page 44-45, section 5.2.4).

Response: See MPCA's response to Comment 38 regarding effectively controlled determination for this emission unit.

Comment 43. The commenter provided a summary of their conclusions and recommendations for the Boise White Paper facility. Overall, the commenter recommended that MPCA require a four-factor analysis for NO_X control strategies for Boiler 2 and evaluate the addition of quaternary air to the Recovery Furnace if it is not already so-equipped (comment letter page 45, section 5.2.5).

Response: The MPCA appreciates the comments made. This comment is a summary of the commenters other comments, which are addressed in Comment 38 through Comment 42. See MPCA's response to Comment 38 through Comment 42.

Comment 44. The commenter provided a narrative summary regarding Minnesota taconite facilities, U.S. EPA's Taconite Regional Haze FIP promulgated in 2013 and revised in 2016, the distance to Voyageurs National Park and Isle Royale National Park, the 2017 national emissions inventory summary of plantwide mercury, particulate matter, NO_X, and SO_2 emissions. The commenter disagreed with MPCA's effectively controlled determination for the indurating furnaces at the taconite facilities.

The commenter also references specific parts of U.S. EPA's Taconite Regional Haze FIP including a quoted portion regarding evaluating Selective Catalytic Reduction (SCR) with reheat, references to the BART analyses/determinations, the ongoing negotiations between U.S. EPA and the taconite facilities,

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[14] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*

and states that the ongoing negotiations between U.S. EPA and the taconite facilities do not exempt the facilities from review in this planning period.

Overall, the commenter stated that their analyses demonstrate that controls are technically feasible, cost-effective, and may be considered reasonable (comment letter page 46-48, section 6.1).

Response: Comments surrounding the history of Minnesota's regional haze efforts are noted. The MPCA believes the commenter provided these details as background information to support comments made later in their letter. The MPCA provided similar information in the draft Regional Haze SIP in Section 1.3 (Taconite FIP summary), Section 2.3.2 (distance to Minnesota Class I areas), and Section 2.3.5 (heat input and NO_X/SO_2 emissions data). The MPCA addresses the comments that use these details throughout the responses to this commenter.

Regarding the effectively controlled determination for the indurating furnaces at the taconite facilities, U.S. EPA's August 2019 Guidance provides that a state is not required to evaluate all sources of emissions in each implementation period, which is consistent with the iterative planning process that is setup by the Regional Haze Rule.[15] As discussed in Section 2.3 of the draft Regional Haze SIP, MPCA describes how it determined which sources initially selected to analyze were ultimately removed from the four-factor analysis process and how the removal of those sources was reasonable considering the factors described in U.S. EPA's August 2019 Guidance.

The MPCA added additional text to Sections 2.3.4, 2.3.5, and 2.4.8 of the draft Regional Haze SIP to inform the reader how the Taconite FIP, and ongoing negotiations between U.S. EPA and the Minnesota taconite facilities, were evaluated as part of the decision to not select these sources for an analysis of control measures in this implementation period.

While MPCA did not evaluate SCR for the taconite sources in this implementation period, MPCA believes this was reasonable given the circumstances surrounding the Taconite FIP. The potential that the applicable emission limits in the Taconite FIP could change highlights the sensitivity of the outcome of any four-factor analyses that could be conducted for these facilities at this time. As the baseline emission rate, used as the starting point for a four-factor analysis, could change depending on the outcome of the settlement discussions, so could any decisions on what emission control measures are necessary to make reasonable progress after identifying the relevant factors. This also informed MPCA's decision to not select these sources for an analysis of control measures in this implementation period to distribute the analytical work needed for the regional haze program across multiple implementation periods.

The MPCA addresses the commenter's review and analysis of potential control measures and their finding that emission control measures may be technically feasible and cost-effective in the response to Comment 45 through Comment 51.

Comment 45. The commenter recommended that MPCA require all taconite facilities conduct four-factor analyses evaluating how an integrated approach to emission control improvements could reduce visibility-impairing emissions (comment letter page 48, section 6.2.1).

Response: The MPCA appreciates the suggestion to consider potential emission reduction measures from a multi-pollutant perspective. The MPCA believes this is a large undertaking that requires additional time to properly account for the relevant factors, accurately estimate the potential emission reductions, and prepare the associated cost estimates for the potential emission control measures. During the FLM consultation period, the U.S. NPS made the same comment and request, MPCA

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[15] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 9.

acknowledged that request and stated they would consider this idea as part of future regional haze planning efforts.

Comment 46. The commenter disagreed with MPCA's determination that Lines 1 and 2 are effectively controlled for this implementation period and provided recommendations for the United Taconite - Fairlane Plant based on their analyses of NO_X, SO_2, and particulate matter control strategies (comment letter page 48, section 6.2.1).

Response: See MPCA's response to Comment 44 regarding MPCA's effectively controlled determination for this facility and Comment 45 regarding an integrated approach to evaluating NO_X, SO_2, and particulate matter control strategies.

Comment 47. The commenter provided a narrative summary regarding United Taconite facility characteristics, specifically the emission units of interest, existing control equipment, the applicable BART emission limits and NO_X control equipment needed to meet the limits, distance to Voyageurs National Park, and the reported NO_X, SO_2, and particulate matter emissions from the emission units of interest (comment letter page 49-50, section 6.2.2).

Response: The MPCA provided similar information in the draft Regional Haze SIP in Section 2.3.2 (distance to Minnesota Class I areas) and Section 2.3.5 (BART limits, heat input, and NO_X/SO_2 emissions data). The MPCA believes the commenter provided these details as background information to support their comments. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 48. The commenter provided comments and recommendations surrounding a NO_X four-factor analysis for the indurating furnaces at the United Taconite facility. The commenter recommended contacting an SCR vendor regarding the application of SCR to United Taconite's operations and provided comments regarding issues the facility raised for SO_2, NO_X, ammonia slip, and mercury with the implementation of SCR.

The commenter disagreed with the values used for system heat input rate, catalyst lifespan/cost, interest rate, control efficiency, inlet temperature, natural gas usage, and inlet NO_X emissions in the cost evaluations.

Overall, the commenter recommended an integrated approach to reducing NO_X, SO_2, and particulate matter emissions (comment letter page 50-56, section 6.2.3).

Response: The MPCA appreciates the detailed review and comments provided on the cost estimates prepared by the facility. The MPCA will consider these comments and recommendations, alongside the suggestion to consider potential emission reduction measures in an integrated approach, as part of future regional haze planning efforts.

Comment 49. The commenter provided comments and recommendations surrounding an SO_2 four-factor analysis for the indurating furnaces at the United Taconite facility. The commenter provided recommendations for what they believe are potentially feasible SO_2 control strategies with new particulate matter controls (i.e., dry sorbent injection, spray dry absorption, or gas suspension absorption).

The commenter disagreed with the values the facility used for interest rate, equipment lifespan, and control efficiency in the cost evaluations.

Overall, the commenter recommended an integrated approach to reducing NO_X, SO_2, and particulate matter emissions (comment letter page 56-58, section 6.2.4).

Response: The MPCA appreciates the detailed review and comments provided on the cost estimates prepared by the facility. The MPCA will consider these comments and recommendations, alongside the suggestion to consider potential emission reduction measures in an integrated approach, as part of future regional haze planning efforts.

Comment 50. The commenter provided comments and recommendations surrounding a particulate matter four-factor analysis for the indurating furnaces at the United Taconite facility. The commenter provides a summary of their particulate matter emission calculations from the indurating furnaces to support the estimated reductions identified in the integrated approach to reducing NO_X, SO_2, and particulate matter emissions (comment letter page 58-59, section 6.2.5)

Response: The MPCA appreciates the detailed review and comments provided on the cost estimates prepared by the facility. The MPCA will consider these comments and recommendations, alongside the suggestion to consider potential emission reduction measures in an integrated approach, as part of future regional haze planning efforts.

Comment 51. The commenter provided a summary of their conclusions and recommendations for the United Taconite facility. Overall, the commenter recommended that MPCA consider NO_X, SO_2, and particulate matter controls for Lines 1 and 2 at the United Taconite facility as well as other taconite facilities in Minnesota (comment letter page 59, section 6.2.6).

Response: The MPCA appreciates the comments made. This comment is a summary of the commenters other comments, which are addressed in Comment 44 through Comment 50. See MPCA's response to Comment 44 through Comment 50.

Comment letter 3 - Minnesota Land and Manoomin Protection Project Fellowship Team with Public Lab

Comment 52. The commenter celebrates the progress in reducing NO_X and SO_2 emissions that contribute to haze and look forward to further reductions in air pollutants (comment letter page 1).

Response: Comment noted.

Comment 53. The commenter pointed to the sources of air pollution, specifically the contributions from Minnesota compared to other states, and stated that reducing air pollution within Minnesota will have the largest impact in meeting the goals set forth in the SIP. The commenter continued that Minnesota wouldn't be able to meet emission reduction targets while continuing to permit industries that emit air pollution, adding that preventing an industry from operating in the first place is the biggest reducer of air pollutants (comment letter page 1).

Response: Any future air permits issued by MPCA will comply with current federal and state standards. This could include required controls, emission limitations or other measures considered in this Regional Haze update for existing facilities. Any new permit would be considered "adequately controlled" under the analysis used in this program.

Comment 54. The commenter identified the Huber Frontier Project, an oriented strand board (OSB) facility, that would be located in Cohasset, Minnesota, and pointed to the environmental assessment worksheet (EAW) that was prepared for the project. The commenter identified the various air pollutants that the EAW identified would emit as part of the facility operations, and the distance to Voyageurs and Boundary Waters Class I areas (comment letter page 1).

Response: Any future air permits issued by MPCA will comply with current federal and state standards. This could include required controls, emission limitations, or other measures considered in this Regional Haze update for existing facilities. Any new permit would be considered "adequately controlled" under the analysis used in this program. The commenter can share comments or concerns about specific permits through the EAW and permit public notice processes.

Comment 55. The commenter identified and disagreed with the Huber EAW conclusion that the facility would have no adverse impacts on visibility in Minnesota Class I areas. The commenters reasoned that the EAW was a preliminary assessment that only considered a few of the pollutants that the facility would emit, the assessment in the EAW was prepared by the facility itself, and that air pollution is cumulative and other facilities contribute to pollution in Minnesota as well. The commenter pointed to the proposed Talon-Rio Tinto Mine near Tamarack, Minnesota and the Eagle Mine in Michigan (comment letter page 1).

Response: The Regional Haze SIP does not directly consider or address the Huber EAW. The commenter can share comments or concerns about that project through the EAW and permit public notice process.

Comment 56. The commenter raised concerns regarding the impact of air pollution on people in general and the impacts of air pollution from the Huber and Talon Mine facilities on resources in the Boundary Waters and Voyageurs for which the Anishinaabe people (referred to as Chippewa in treaties) have treaty rights. The commenter noted that negative impacts to these resources (such as wild rice/manoomin, game, and fish) is detrimental to the survival of the Anishinaabe people as they provide sustenance, economic opportunities, and are culturally important (comment letter page 1).

Response: The MPCA has consulted with environmental staff from tribal nations in the development of this SIP. Coordination and collaboration with tribal governments will be important to future work on Regional Haze. See section 2.9.3 of Minnesota's Regional Haze SIP for a summary of engagement with tribal nation environmental staff.

Comment 57. The commenter provides an example, using a nickel-copper mine in Russia, to illustrate the potential impacts a mine can have on local resources and recommends that the State of Minnesota should not permit facilities that will likely emit toxic metals and substances that can concentrate in the environment. The commenter suggests that instead the State of Minnesota should look at opportunities to create long-lasting jobs and a thriving economy through community-led renewable energy initiatives that sustain the environment and people (comment letter page 1).

Response: Comment noted.

Comment 58. The commenter identified the non-binding targets in the Regional Haze SIP and recommended that the State of Minnesota instead creating binding targets, which would require the Minnesota Legislature enact legislation to comply with the federal mandated haze plan (comment letter page 1).

Response: The MPCA will continue to analyze additional options for emissions reductions in future Regional Haze progress reports and comprehensive updates.

Comment 59. The commenter summarized their comments and suggested that the Regional Haze SIP focus on preventing new pollution from entering the region in addition to reducing pollution from existing sources. The commenter added that while meeting the goals of the SIP is crucial, so is protecting the environment, treaty-guaranteed usufructuary rights, and humans from the harm of air pollution (comment letter page 1).

Response: Comment noted.

Comment letter 4 - Southern Minnesota Beet Sugar Cooperative (SMBSC)

Comment 60. The commenter provided a summary of communications/interactions between the facility and MPCA, and stated that MPCA's recommendation for the facility to install NO_X emission controls lacks technical basis and is arbitrary and capricious when all relevant factors are considered. The commenter organizes their comments in this section into three topic areas by focusing on Q/d screening considerations, the claim there is a lack of technical basis, and the claim of arbitrary targeting (comment letter page 1, section I).

Response: The MCPA disagrees with the commenter. The MPCA's determination that NO_X emission controls were necessary to continue making reasonable progress was based on the requirements of the Regional Haze Rule and the recommendations from the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The MPCA references throughout the draft Regional Haze SIP when decisions and analyses are based on the Regional Haze Rule requirements and U.S. EPA guidance. The MPCA applied this decision making process consistently across multiple facilities throughout the development of Minnesota's Regional Haze SIP. The MPCA addresses the commenter's three topic areas in subsequent responses to comments, which are addressed in Comment 61 through Comment 74.

Comment 61. The commenter stated that the facility should not have been selected by MPCA to conduct a four-factor analysis at the outset. The commenter summarized MPCA's Q/d analysis, specifically how the analysis changed from how it was initially applied (i.e., selecting the top 80% of sources using Q/d as calculated on an individual emission unit basis), the consultation between MPCA and the FLMs regarding the source selection process and Q/d analysis, and the changes made to the final source selection. The commenter disagreed with the use of facility-wide emissions in MPCA's Q/d analysis, the inclusion of additional sources in the source selection process (specifically SMBSC), the effective Q/d threshold used, and the difference in Q/d threshold for Minnesota compared to Wisconsin. Overall, the commenter claimed that MPCA arbitrarily selected Boiler 1 at SMBSC for a four-factor analysis (comment letter page 1-2, section I.A.).

Response: The MPCA disagrees with the commenter. While the facility may disagree with the approach MPCA has taken for source selection, that does not make it unreasonable or arbitrary. The MPCA documents the decisions made in the source selection process in Section 2.3.6 of the draft Regional Haze SIP, including where decisions to use facility-wide emissions and evolved based on discussions between MPCA and FLMs. These conversations between MPCA and FLMs resulted in MPCA sending requests for a four-factor analysis to four additional facilities, including Southern Minnesota Beet Sugar Cooperative. The MPCA did not send RFI letters to all facilities of interest identified by the FLMs, but the inclusion of the four additional sources was based on the considerations described in Section 2.3.6 of the draft Regional Haze SIP to include a sufficient set of sources in the source selection step with potential for visibility benefits from the control measure analysis.

Regarding MPCA's Q/d analysis, the Q/d "threshold" of 4.6 is only identified as the resultant Q/d value that corresponds to the top 85% of visibility impacts via Q/d; this value was not a consideration in arriving at the sources selected for analysis. The MPCA would also like to reiterate that these Q/d "thresholds" were identified and specifically called out in the draft Regional Haze SIP in response to a request to do so from U.S. EPA on a pre-public notice version of the draft Regional Haze SIP. The MPCA evaluated sources using Q/d and selected sources that comprised the top 85% of visibility impacts via Q/d from Minnesota stationary sources. The Q/d values presented in the Regional Haze SIP for Minnesota Class I areas were used to determine the top 85% of visibility impacts and MPCA selected sources based on if they were within the top 85%.

The commenter states that Wisconsin used a Q/d value of 10 to select sources. However, the other state in the Lake Michigan Air Director's Consortium (LADCO) region with Class I areas (Michigan) used a Q/d value of 4 in their source selection process.[16] While other states may have different Q/d values than what MPCA used, using other neighboring states are values because they are higher and would result in SMBSC not being selected would be arbitrary. The MPCA's threshold for source selection is comparable to thresholds used by many other states in this regional haze implementation period and is neither aggressive nor arbitrary.

Additionally, consultation with the FLMs is a requirement of the Regional Haze program, as identified in 40 CFR 51.308(i), and the opportunity for the FLMs to provide information and recommendations that inform the state's decisions is clearly required by the rule. Overall, MPCA's approach is reasonable because it is grounded in both the requirements of the Regional Haze Rule and U.S. EPA's guidance.

Comment 62. The commenter expressed concerns over MPCA's use of a Q/d analysis, versus other methods for the source selection process, and pointed to progress made in addressing visibility impairment in the Boundary Waters and Voyageurs Class I areas being below the uniform rate of progress. The commenter provided a reference to U.S. EPA's August 2019 Guidance and the information contained within regarding techniques to examine source impacts (e.g., Q/d analyses, trajectory analyses, residence time analyses, and photochemical modeling). The commenter also referenced a trajectory analysis provided with the four-factor analysis to argue that the emissions from Boiler 1 at the facility rarely reach, cause, or impact visibility conditions at the Boundary Waters or Voyageurs Class I areas.

The commenter also pointed to practices for evaluating visibility impacts under the Prevention of Significant Deterioration (PSD) program and FLM guidance regarding visibility analyses under that program as supporting reasons for their concerns over MPCA's Q/d analysis (comment letter page 2-4, section I.A.).

Response: The MPCA's use of a Q/d analysis to select sources, as acknowledged by the commenter, is identified as a reasonable method in U.S. EPA's August 2019 Guidance. While the facility may disagree with the outcome of the approach MPCA has taken, and would have preferred that MPCA conduct a more complicated and resource intensive technique like a trajectory analysis for source selection, that does not make it unreasonable. The MPCA's Q/d analysis is rooted both in EPA guidance and follows the requirements of the regional haze rule as described in Section 2.3.6 of the draft Regional Haze SIP. The MPCA treated all facilities equally and consistently by evaluating emissions and distance to Class I areas in this analysis, and to use the facility-provided trajectory analysis to remove SMBSC from the source selection process would be arbitrary and inconsistent.

While visibility projections are below the URP glidepath for both the Boundary Waters and Voyageurs, the U.S. EPA has reiterated that this is not a "safe harbor" in multiple instances.[17] The U.S. EPA has stated that 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."[18] Additionally, the U.S. EPA, in its July 2021 Clarification Memo, identifies that states may assess visibility impacts/benefits and discusses other suggestions surrounding that topic. Briefly, the U.S. EPA suggests that it would not be appropriate to reject a control measure because the

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[16] *See* Michigan, Regional Haze Second Planning Period (May 2021), *https://www.michigan.gov/egle/about/organization/air-quality/state-implementation-plan*.
[17] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 2, 12, 13, 15; Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).
[18] *See* Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).

effect would be considered "small" as those sources still contribute to visibility impairment and have a meaningful impact in the aggregate.[19] The fact that current visibility conditions have improved since the first implementation period in Minnesota Class I areas had no bearing on MPCA's determination of the sources to select to prepare four-factor analyses. Furthermore, additional improvement in visibility conditions are still needed as Minnesota Class I areas haven't reached the overall goal of returning these areas to natural visibility conditions.

Furthermore, the Q/d threshold identified in FLM guidance for PSD visibility evaluations addresses new sources of air pollution and SMBSC is not a new source. While this is a valuable screening tool for FLMs in PSD evaluations, it is not a bright-line test as the commenter suggests. The FLM guidance clarifies that FLMs would like to be notified of all new sources proposed near Class I areas, regardless of the Q/d value, and specifies that it is not a "one-size-fits-all" determination and that some permits may require additional scrutiny. To summarize, the FLMs decide which PSD permit applications to review on a case-by-case basis depending on the potential impacts to air quality related values and the Q/d value identified in the FLM guidance is not directly applicable to the requirements established in the Regional Haze Program.

Comment 63. The commenter stated that MPCA lacks a technical basis to support that new NO_X emission controls at SMBSC are needed to make reasonable visibility progress. The commenter disagrees with MPCA's determination that NO_X controls should be required in general and provides additional information to support their argument. In summary, this information included the distance and cardinal direction from the facility to the Boundary Waters and Voyageurs Class I areas, a wind rose diagram that shows the predominant wind directions near the facility, and a forward-trajectory analysis that looks at the number of days emissions from the facility reach the Class I areas.

The commenter argues that based on this information that NO_X controls are not cost-effective and suggests "there will be negligible or no visibility improvement resulting from the controls" (comment letter page 4-5, section I.B.).

Response: The MPCA disagrees with the commenter. While the facility may disagree with the approach MPCA has taken, and would have preferred that MPCA conduct a more complicated and resource intensive technique that considers direction for source selection, that does not make it unreasonable. The MPCA's Q/d analysis, which does consider distance, is rooted both in EPA guidance and follows the requirements of the regional haze rule as described in Section 2.3.6 of the draft Regional Haze SIP. The MPCA treated all facilities equally and consistently by evaluating emissions and distance to Class I areas in this analysis, and to use the facility-provided trajectory analysis and wind rose to remove SMBSC from the control evaluation process would be arbitrary and inconsistent. The MPCA has evaluated the control measure analyses submitted by all selected sources by consistently applying the four statutory factors to determine which measures are needed to make reasonable progress. The MPCA did not consider the visibility benefits of individual control measures alongside the four statutory factors when evaluating emission control measures. The MPCA documents the decisions made in determining the control measures needed to make reasonable progress in Section 2.5 of the draft Regional Haze SIP, including a discussion on cost evaluation in Section 2.5.1 and visibility benefits in Section 2.5.5 of the draft Regional Haze SIP.

Additionally, as discussed in MPCA's response to Comment 62 it would not be appropriate to reject a control measure because the effect would be considered "small". The fact that current visibility conditions have improved since the first implementation period in Minnesota Class I areas had no bearing on MPCA's determination of the emission controls necessary to continue making reasonable

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[19] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 14

progress. Furthermore, additional improvement in visibility conditions are still needed as Minnesota Class I areas haven't reached the overall goal of returning these areas to natural visibility conditions.

Comment 64. The commenter stated that MPCA should not apply a universal cost effectiveness threshold equally to all facilities without considering distance, wind directions, and trajectories to determine if NO_X controls are needed for reasonable progress. The commenter added that they believe the cost threshold referenced is unnecessarily aggressive given the state of visibility conditions in the Boundary Waters and Voyageurs Class I areas. The commenter identified that they recalculated the cost of SNCR at "higher than $5,700/ton NO_X removed" and should not be considered cost effective.

The commenter also stated that MPCA did not consider visibility impacts to determine if controls would be required for reasonable progress, would not complete modeling of proposed control measures, and would not consider the results of modeling performed by the facility to evaluate the impacts on visibility conditions from NO_X and/or SO_2 controls.

The commenter also stated that MPCA is intentionally ignoring visibility improvement at the Boundary Waters and Voyageurs Class I areas to determine whether facilities should install controls, which they found to be concerning and logically inconsistent. The commenter stated that MPCA's position is that visibility is not a consideration for the four-factor analyses, but additional controls are needed to make reasonable progress on visibility improvement, and therefore MPCA is being inconsistent and arbitrary.

The commenter requests MPCA to supply proof that new NO_X controls are reasonable and required to make reasonable progress in absence of an individual facility modeled visibility impact analysis. The commenter references the commenter-provided supplemental analysis, and the commenter considers MPCA approach to have no technical basis (comment letter page 5-6, section I.B.).

Response: The MPCA disagrees with the commenter. The MPCA's determination that NO_X emission controls were necessary to continue making reasonable progress was based on following the requirements of the Regional Haze Rule and the recommendations from the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. As identified in 40 CFR § 51.308(f)(2), the emissions limitations, compliance schedules, and other measures necessary to make reasonable progress are determined pursuant to 40 CFR § 51.308(f)(2)(i) through (iv). The MPCA documents the decisions made in determining the control measures needed to make reasonable progress in Section 2.5 of the draft Regional Haze SIP. The MPCA included a discussion on cost evaluation and how MPCA arrived at the recommended emission reduction measures needed to make reasonable progress, including measures at SMBSC, in Section 2.5.1 of the draft Regional Haze SIP. Furthermore, the cost effectiveness calculated by the commenter (i.e., $5,700 per ton) is still below the upper end of costs of control measures the MPCA determined were needed to make reasonable progress.

The MPCA states in Sections 2.4.7 and 2.5.5 of the draft Regional Haze SIP that it did not consider the visibility benefits of individual control measures alongside the four statutory factors when evaluating emission control measures. The requirements of the Regional Haze Rule and the recommendations from the U.S. EPA August 2019 Guidance and July 2021 Clarification memo do not ask or require states to consider visibility when conducting a four-factor analysis. The U.S. EPA identifies that states can consider visibility benefits, so long as those factors are considered in a reasonable way that does not undermine or nullify the four statutory factors.[20] The MPCA was consistent in its review and evaluation of the four-factor analyses prepared by facilities.

[20] *See* July 2021 EPA Clarifications*, supra,* at 4 (quoting U.S. EPA, Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans, EPA-HQ-OAR-2015-0531, at 156 (Dec. 2016)).

The MPCA has evaluated the control measure analyses submitted by all selected sources by consistently applying the four statutory factors to determine which measures are needed to make reasonable progress. The MPCA did not consider the visibility benefits of individual control measures alongside the four statutory factors when evaluating emission control measures, and to use the facility-provided trajectory analysis and wind rose to remove SMBSC from the control evaluation process would be arbitrary and inconsistent.

Furthermore, the commenter's suggestion that it is required to evaluate the individual visibility impacts of potential control measures as part of the four factor analysis is counter to multiple indications from the U.S. EPA regarding visibility impacts. Additionally, as discussed in MPCA's response to Comment 62 and Comment 63, it would not be appropriate to reject a control measure because the effect would be considered "small". While visibility projections are below the URP glidepath for both the Boundary Waters and Voyageurs, the U.S. EPA has reiterated that this is not a "safe harbor" in multiple instances.[21] The U.S. EPA has stated that 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."[22] Additionally, the U.S. EPA, in its July 2021 Clarification Memo, identifies that states may assess visibility impacts/benefits and discusses other suggestions surrounding that topic. Briefly, the U.S. EPA suggests that it would not be appropriate to reject a control measure because the effect would be considered "small" as those sources still contribute to visibility impairment and have a meaningful impact in the aggregate.[23] The fact that current visibility conditions have improved since the first implementation period in Minnesota Class I areas had no bearing on MPCA's determination of the emission controls necessary to continue making reasonable progress. Furthermore, additional improvement in visibility conditions are still needed as Minnesota Class I areas haven't reached the overall goal of returning these areas to natural visibility conditions.

Comment 65. The commenter stated and identified other portions of the draft Regional Haze SIP that they believe demonstrate NO_X controls for SMBSC are unwarranted. The commenter identified information in Section 2.1.6 of the SIP document regarding average yearly improvement to the monitored visibility impairment at Boundary Waters and Voyageurs, adjustments to the 2064 end goal of natural visibility conditions, and stated that new NO_X controls don't appear to be needed to reach natural visibility conditions if the trend in visibility improvement continues.

The commenter identified the contribution analyses in Section 2.2.3 of the SIP document and reiterated their comments that reductions at the facility would have a small impact on visibility improvement.

The commenter identified the interstate consultation summary in Section 2.9.1, disagreed with MPCA's statement that Minnesota is a major contributor to visibility impairment at Boundary Waters and Voyageurs, and stated that MPCA is focusing unnecessarily on smaller industrial sources compared to other LADCO states (comment letter page 6-8, section I.B.).

Response: While current visibility conditions have improved since the first implementation period in Minnesota Class I areas, they have not reached the natural visibility conditions required by the Regional Haze program. The commenter's statement that additional emission reduction measures don't appear to be needed since visibility has improved is a flawed argument. Additional emission reductions have occurred over the 2009 through today time period referenced by the commenter, leading to the

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[21] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 2, 12, 13, 15; Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).
[22] *See* Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).
[23] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 14

referenced improvement in visibility conditions. Regardless, as Minnesota Class I areas haven't reached natural conditions, MPCA must continue to evaluate emission reductions under the Regional Haze program to continue making reasonable progress on addressing visibility impairment in these Class I areas.

Additionally, as discussed in MPCA's response to Comment 62 and Comment 63, it would not be appropriate to reject a control measure because the effect would be considered "small". While visibility projections are below the URP glidepath for both the Boundary Waters and Voyageurs, the U.S. EPA has reiterated that this is not a "safe harbor" in multiple instances.[24] The U.S. EPA has stated that 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."[25] Additionally, the U.S. EPA, in its July 2021 Clarification Memo, identifies that states may assess visibility impacts/benefits and discusses other suggestions surrounding that topic. Briefly, the U.S. EPA suggests that it would not be appropriate to reject a control measure because the effect would be considered "small" as those sources still contribute to visibility impairment and have a meaningful impact in the aggregate.[26] The fact that current visibility conditions have improved since the first implementation period in Minnesota Class I areas had no bearing on MPCA's determination of the emission controls necessary to continue making reasonable progress. Furthermore, additional improvement in visibility conditions are still needed as Minnesota Class I areas haven't reached the overall goal of returning these areas to natural visibility conditions.

Comment 66. The commenter stated that they recognize that visibility improvement results from many reductions from many sources, and that they are not averse to considering controls where there appear to be real, cost-effective benefits within an appropriate regulatory framework, but object to the conclusions contained in the draft Regional Haze SIP. The commenter stated that the document has been manipulated to recommend expensive controls specifically for SMBSC without any visibility benefits (comment letter page 8, section I.B.).

Response: The MPCA disagrees with the commenter. While the facility may disagree with the approach taken and results, that does not make MPCA's determination of control measures needed to continue making reasonable progress unreasonable or inconsistent. The MPCA has evaluated the control measure analyses submitted by all selected sources by consistently applying the four statutory factors to determine which measures are needed to make reasonable progress. The MPCA's determination that NO_X emission controls were necessary to continue making reasonable progress was based on following the requirements of the Regional Haze Rule and the recommendations from the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. For specific examples and responses, see MPCA's response to Comment 60 through Comment 65.

Comment 67. The commenter stated and identified different factors they consider to be indicators of arbitrary and capricious targeting by MPCA and FLMs for SMBSC to install new NO_X controls.

Specifically, the commenter identified the option that MPCA provided of fuel switching in meetings with SMBSC, the only additional sources that MPCA selected for a four-factor analysis were coal-fired sources, and reiterated that SMBSC was not originally included in MPCA's request to prepare four-factor analyses. The commenter stated that MPCA's focus on fuels instead of visibility benefits is not consistent with regulations or guidance.

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[24] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 2, 12, 13, 15; Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).
[25] *See* Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).
[26] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 14

The commenter repeated the concerns expressed in previous comments regarding MPCA's Q/d analysis (see Comment 62) and stated that they were singled out and purposely selected due to FLMs specific interests.

The commenter repeated the concerns expressed in previous comments regarding facility modeling of visibility impact from controls (see Comment 64) and references 40 CFR § 51.308(f)(2)(iv) regarding the five additional factors states must consider in developing a long-term strategy. The commenter states that MPCA has failed to fulfill its regulatory obligations to consider that anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions by not completing modeling to demonstrate the impact on visibility with the proposed changes in the SIP including the recommendation for SMBSC to install NO_X controls.

The commenter stated that Minnesota is already well on the way to achieving natural visibility at both the Boundary Waters and Voyageurs Class I areas with no changes to SMBSC's emissions, therefore no new NO_X controls on SMBSC should be needed to make reasonable progress. The commenter also acknowledges that the 2028 modeling MPCA conducted is conservative in that it doesn't account for all planned emission reductions.

The commenter repeated the concerns expressed in previous comments regarding their statement that MPCA had not considered the level of visibility improvement in determining if emission controls were needed, MPCA stating that emission controls are needed to make reasonable progress (see Comment 64), and restated that MPCA is being inconsistent, unreasonable, and arbitrary in doing so (comment letter page 8-9, section I.C.).

Response: The MPCA disagrees with the commenter. While the facility may disagree with the source selection approach MPCA has taken, and would have preferred that MPCA conduct a more complicated and resource intensive technique that considers direction for source selection, that does not make it unreasonable. The MPCA's source selection process is rooted both in EPA guidance and follows the requirements of the regional haze rule as described in Section 2.3.6 of the draft Regional Haze SIP. The MPCA treated all facilities equally and consistently by evaluating emissions, with no consideration for the fuel type, and distance to Class I areas in this analysis. For example, wood-fired sources at Hibbing and Virginia Public Utilities were selected for the four factor analysis process and coal-fired sources were not selected for the four factor analysis process at Blandin Paper, Minnesota Power - Hibbard Renewable Energy Center, Otter Tail Power, American Crystal Sugar - Moorhead, and Duluth Steam Plant 1 (see section 2.3.6 of the draft Regional Haze SIP).

Regarding the concept of fuel switching, it is reasonable for MPCA to discuss fuel-switching as a potential emission control measure and MPCA raised the topic of fuel-switching with multiple facilities when meeting to discuss initial recommendations for potential control measures. Additionally, U.S. EPA's August 2019 Guidance specifically identifies fuel-use changes as a type of emission control measure that states may consider.[27]

Regarding the commenter's reiterated concerns, see MPCA's response to Comment 60 through Comment 65.

Comment 68. The commenter provided several comments regarding cost analyses prepared by MPCA and cost analyses prepared by the U.S. NPS.

The commenter disagreed with the values used in MPCA and U.S. NPS cost analysis for interest rate, pointing to the current bank prime interest rate in comparison to the values presented in the draft

[27] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 29.

Regional Haze SIP, and various reagent costs (e.g., fuel, water, urea) being estimated using default values instead of being scaled via inflation as SMBSC has done in their cost analyses (comment letter page 9-10, section I.C.).

Response: The MPCA acknowledges that multiple factors influence the outcome of any cost-estimate that is prepared for the evaluation of air pollution controls, such as a four-factor analysis. In Sections 2.4 and 2.5 of the draft Regional Haze SIP, MPCA presented both costs it estimated, as well as costs estimated by the facility. As described in Section 2.5.1 of the draft Regional Haze SIP, the purpose behind the adjusted cost information (e.g., interest rate, reagent costs, etc.) was to provide consistency in the basic factors used across emission units to aid in the evaluation of whether a control measure was cost-effective or not. The MPCA believes it has reasonably estimated these parameters for the potential control measures based on information available in the U.S. EPA's Control Cost Manual.[28]

Comment 69. The commenter identified and disagreed with many comments from the U.S. NPS regarding control cost analyses in general with respect to SMBSC.

The commenter disagreed with the U.S. NPS statements that there are cost-effective controls for this implementation period and that the value for the CEPCI index used by SMBSC's consultant was too high.

The commenter also stated that they did not evaluate specific cost evaluations prepared by the U.S. NPS for wet flue gas desulfurization and other control technologies.

The commenter disagreed with the U.S. NPS comments regarding equipment life assumptions, applicability of vendor estimates, operating costs, and retrofit factors (comment letter page 10-11, section I.C.).

Response: See MPCA's response to the U.S. NPS comments regarding Southern Minnesota Beet Sugar Cooperative (Comment 28 through Comment 33).

Comment 70. The commenter provided comments regarding the uncontrolled emission rates and operating hours assumption that MPCA used in the cost analysis. The commenter notes that they used the 2028 modeling emissions inventory as the basis for the NO_X and SO_2 emissions and states that the operating hour value MPCA uses in the cost estimates is too low (comment letter page 10, section I.C.).

Response: The MPCA revisions to the emissions and operating data were based on the data the facility reported to MPCA's annual emissions inventory database for 2017. The operating hour value is the value predicted for operating hours by U.S. EPA's Control Cost Manual spreadsheets.

Comment 71. The commenter identified specific comments regarding SNCR/SCR NO_X controls. The commenter identified MPCA's changes to coal higher heating value, annual fuel usage, and inlet/outlet NO_X emission rate including its relation to the normalized stoichiometric ratio (comment letter page 11-13, section I.C.).

Response: The MPCA revisions to the emissions and operating data were based on the data the facility reported to MPCA's annual emissions inventory database for 2017. The coal higher heating value was calculated based on the heat input (3,082,544 MMBtu heat input) and coal use (171,275 tons coal) reported in 2017.

Comment 72. The commenter identified and disagreed with many comments from the U.S. NPS regarding SNCR/SCR NO_X controls.

[28] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS, *supra.*

The commenter agreed with the 30% NO_X reduction suggested by the U.S. NPS as a more accurate representation of the expected NO_X reduction with respect to MPCA's values for inlet/outlet NO_X emission rate.

The commenter disagreed with the U.S. NPS comments regarding retrofit factors, the values used for supplemental natural gas combustion for a heat exchanger in the reheat system evaluated alongside SCR, the choice of method to estimate catalyst replacement cost, and equipment/catalyst lifespan (comment letter page 11-13, section I.C.).

Response: Comments noted. See MPCA's response to the U.S. NPS comments regarding Southern Minnesota Beet Sugar Cooperative (Comment 28 through Comment 33).

Comment 73. The commenter identified specific comments regarding SO_2 controls. The commenter notes an incorrect footnote in the spray dry absorber capital costs in MPCA's cost revisions (comment letter page 13, section I.C.).

Response: Comment noted. Regarding the identified error in the footnote identified, it appears the incorrect citation was carried forward in the spreadsheet MPCA revised to summarize control cost estimates.

Comment 74. The commenter identified and disagreed with many comments from the U.S. NPS regarding SO_2 controls. The commenter disagreed with the U.S. NPS comments regarding SO_2 control efficiencies, the addition of a polishing baghouse versus replacing the existing ESP and associated demolition costs and energy savings, and the cost estimate method used for the addition of a spray dry absorber (comment letter page 13-15, section I.C.).

Response: Comments noted. See MPCA's response to the U.S. NPS comments regarding Southern Minnesota Beet Sugar Cooperative (Comment 28 through Comment 33).

Comment letter 5 - Cleveland-Cliffs Inc. (Cliffs)

Comment 75. The commenter requested MPCA and LADCO work with Canada and in particular Ontario so that future SIP revisions will include more accurate emission estimates and modeling to better quantify these international sources' impact on visibility (comment letter page 1-2).

Response: MPCA and LADCO depend on the U.S. EPA to provide international facility emissions for Canada. The Canada inventories are based on data from Environment Canada. The U.S. EPA modeling platform version 1 technical support document details the Canada emissions.[29] This document is referenced in Section 4.3 of Appendix A, MPCA's Regional Haze Technical Support Document. The Canadian point source data was from the Environment and Climate Change Canada (ECCC) 2015 emission inventory and further prepared for modeling by U.S. EPA. The MPCA has no evidence that the ECCC emissions or the U.S. EPA processing of the emissions used in the modeling are inaccurate. While unable to predict what data will be available for the next SIP implementation period, MPCA anticipates using the best available data. That data may be ECCC emission inventory data representing the appropriate model base year as processed by U.S. EPA.

Comment 76. The commenter requested MPCA refine its data and methods to propose appropriate adjustments to the 2064 endpoint and interim implementation period goals in the 3rd implementation period (comment letter page 2).

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[29] *U.S. EPA TSD for modeling platform version 1. https://www.epa.gov/sites/default/files/2020-11/documents/2016v1_emismod_tsd_508.pdf*

Response: In the Executive Summary, last paragraph, MPCA states "*Leading up to the third regional haze implementation period MPCA expects to continue to annually assess visibility trends, and to contemplate proposing international impact adjustments to the 2064 endpoint and what that might mean for Boundary Waters and Voyageurs in the Regional Haze Program going forward*".

The MPCA anticipates U.S. EPA may revise the Regional Haze Rule and guidance in preparation for the third implementation period, as they did for the second implementation period when U.S. EPA added the concept of the endpoint adjustment. The MPCA expects to monitor U.S. EPA rule and guidance activity leading up to the third implementation period on the issue of endpoint adjustments as well as other issues. The MPCA will continue to take measures in the third implementation period in accordance with any newly revised federal rule and guidance that are practicable with State agency resources and are scientifically defensible.

Comment letter 6 - United States Environmental Protection Agency - Region 5 (U.S. EPA Region 5)

Comment 77. The commenter requested that MPCA make clarifications to U.S. EPA's obligations regarding the Regional Haze Taconite FIP discussed in Section 1.3 of the draft Regional Haze SIP. Specifically, the commenter requested that MPCA note that U.S. EPA does not necessarily respond to comments on a settlement agreement and clarify that a settlement agreement for the U.S. Steel - Minntac facility was already reached (comment letter page 1, comment 1).

Response: The MPCA revised Section 1.3 of the draft Regional Haze SIP by reorganizing the paragraph to clearly indicate that U.S. EPA already reached a settlement agreement with U.S. Steel - Minntac and state that U.S. EPA published a final rule revising the FIP for that facility. The discussion regarding settlement agreements was also revised to identify only the remaining facilities where settlement agreements are expected and removed the language stating that U.S. EPA must respond to any comments received.

Comment 78. The commenter requested that MPCA clarify the meaning of specified text and the column headings in the Tables in Section 2.2.3 that refer to percentages and tons of 2028 emissions (comment letter page 2, comment 2).

Response: MPCA revised the specified text in Section 2.2.3 of the SIP, and corresponding text in Section 4.8.5 of Appendix A, MPCA's Regional Haze Technical Support Document, to read, "*In Northeast Minnesota the most significant sector group contributing to visibility impairment is industry at 4.7% of the region total at both Class I areas (6.5% at Boundary Waters and 7.3% at Voyageurs)*".

MPCA revised table and column headings for Tables within Section 2.2.3 of the SIP and revised the corresponding table column headings for Tables within Section 4.8.5 in Appendix A, MPCA's Regional Haze Technical Support Document, to include "impairment" after "visibility" and "2028" between "annual" and "emissions".

Comment 79. The commenter requested MPCA clarify how the text "*Northeast Minnesota contributes about 40% visibility impairment at both Boundary Waters and Voyageurs. With 60% of the visibility impairment from Minnesota attributed to the rest of the state…*" relates to the percentages in Table 13 and in other similar text and tables (comment letter page 2, comment 3).

Response: MPCA revised the specified text in Section 2.2.3 of the SIP, and corresponding text in Section 4.8.5 in Appendix A, MPCA's Regional Haze Technical Support Document, to clarify that "*Northeast Minnesota contributes about 40% of the state total contribution to visibility impairment at both Boundary Waters and Voyageurs. With the remaining 60% of the state total contribution attributed* *to the rest of the state, the modeling suggests the need for additional focus on vehicles—the top contributing sector group in the Rest of Minnesota region—in the third implementation period*". See the response to Comment 81 for revised text in other parts of the Sections.

Comment 80. The commenter requested MPCA describe the reasons for the large reductions in vehicle NO_X emissions around 66,200 tons in Minnesota, between 2016 and 2028 (comment letter page 2, comment 4).

Response: Section 2.6.1 of the SIP indicates that vehicle emissions were provided by U.S. EPA in their 2016 modeling platform, version 1, and includes a footnote link to U.S. EPA's documentation and for convenience also provided here: https://www.epa.gov/sites/default/files/2020-11/documents/2016v1_emismod_tsd_508.pdf.

Section 4.3 of U.S. EPA's Technical Support Document on the Preparation of Emissions Inventories for the 2016v1 North American Emissions Modeling Platform (March 2021) describes in detail how the emissions projections for vehicles were developed.

Comment 81. The commenter requested that MPCA clarify whether statewide percentages of visibility impairment due to nitrate at Boundary Waters (60%) and Voyageurs (53%) from North Dakota, as well as the other states referenced in Section 2.2.3 of the draft Regional Haze SIP, compare the amount of sulfate to nitrate that comprise a region's total contribution to visibility impairment (comment letter page 2-3, comment 5).

Response: The MPCA revised the specified and similar text within Section 2.2.3 of the SIP, and corresponding text within Section 4.8.5 in Appendix A, MPCA's Regional Haze Technical Support Document, to clarify the meaning of the percentages. For example, North Dakota's section was revised to "*Statewide, North Dakota's contribution to total visibility impairment is 4.8% at Boundary Waters and 5.9% at Voyageurs. Most of that contribution is due to nitrate, 53% at Boundary Waters and 60% at Voyageurs, with the remainder due to sulfate*".

Comment 82. The commenter identified different pages in Section 2.3 of the draft Regional Haze SIP where different Q/d values (4.6 versus 4.7) were identified as "thresholds" in the source selection step and requested that MPCA clarify which value was intended. The commenter also requested that MPCA clarify whether sources were selected based on Q/d or the top 85% of emissions from sources within the state. The commenter noted that selecting the top 85% of emissions would not necessarily correlate with visibility impacts in the same way that Q/d would or in using the other methods discussed in guidance for this regional haze implementation period (comment letter page 3, comment 6).

Response: The MPCA revised the references to Q/d values to indicate that 4.6 is the correct value and the value of 4.7 referenced was a typographical error. The Q/d "threshold" of 4.6 is only identified as the resultant Q/d value that corresponds to the top 85% of visibility impacts via Q/d; this value was not a consideration in arriving at the sources selected for analysis. The MPCA would also like to reiterate that these Q/d "thresholds" were identified and specifically called out in the draft Regional Haze SIP in response to a request to do so from U.S. EPA on a pre-public notice version of the draft Regional Haze SIP.

The MPCA evaluated sources using Q/d and selected sources that comprised the top 85% of visibility impacts via Q/d from Minnesota stationary sources. The Q/d values presented in the Regional Haze SIP for Minnesota Class I areas were used to determine the top 85% of visibility impacts and MPCA selected sources based on if they were within the top 85%. The MPCA also revised the text throughout the draft Regional Haze SIP to reflect that sources were selected based on representing the top 85% of visibility impacts via Q/d from Minnesota stationary sources.

Comment 83. The commenter requested that MPCA include and provide a full copy of LADCO's October 14, 2020 memo regarding "Description of the sources and methods used to support Q/d analysis for the 2nd Regional Haze Planning Period" instead of only a weblink (comment letter page 4, comment 7).

Response: The information contained in the referenced memo was provided to LADCO member states prior to the final version of the LADCO Regional Haze 2018-2028 Planning Period TSD and is provided directly in Sections 5.1 and 5.2 of the LADCO TSD. The LADCO TSD is provided directly in Appendix C, including the finalized version of the information in the October 14, 2020 memo, which MPCA believes fulfills the commenter's request.

Comment 84. The commenter requested that MPCA clarify information contained in the tables in the draft SIP document that display information regarding the Q/d analysis (i.e., Tables 29 and 30). Specifically, the commenter asked if the values for percentile and cumulative percentile reflect only the listed facilities and not overall percentiles that account for contributions from other sources such as mobile, international, or biogenic sources (comment letter page 4, comment 8).

Response: The text preceding the identified tables in Section 2.3.2 already states the emissions data identified is the emission totals from the identified facilities and not from other sources as the commenter suggests. Additional text has been added to clarify that the tables in this section display only Minnesota stationary source emissions.

Comment 85. The commenter requested that MPCA provide additional context in Section 2.3.4 regarding emission projections and the ongoing settlement discussions for the Taconite Regional Haze FIP. Specifically, the commenter requested that MPCA acknowledge these discussions for Table 32, discuss the relative sensitivity of MPCA's projections to potential changes, and elaborate how the final rule revising the Taconite FIP for U.S. Steel - Minntac was considered or how it would impact MPCA's projections (comment letter page 4-5, comment 9).

Response: Additional text was added to Section 2.3.4 and Section 2.3.5 to direct the reader to Section 1.3 for additional information regarding the referenced settlement discussions. Additional text was also included to restate that MPCA considers their estimated emission reductions to be conservative. The MPCA assumed compliance at the least stringent end of the Regional Haze Taconite FIP emission limit ranges. For example, if the emission unit was subject to a limit range of 1.2-1.5 lb NO_X/MMBtu, MPCA assumed the emission unit would be subject to a limit of 1.5 lb NO_X/MMBtu in emission projection calculations). The MPCA also included additional discussion in Section 2.4.8 to inform the reader how MPCA weighed the potential for changes to the Taconite FIP emission limits as part of the decision to not select these sources for an analysis of control measures in this implementation period.

The MPCA's projections for U.S. Steel - Minntac were based on the emission limits that were ultimately finalized by U.S. EPA for the facility, and additional clarification was added to the discussion for U.S. Steel - Minntac in Section 2.3.5 to state that explicitly.

Comment 86. The commenter identified the five years of emissions data and 2028 projections that MPCA provides in Section 2.3.5 and suggested that MPCA should further address whether the identified facilities need to hold emissions to a certain level for reasonable progress, and if those limits should be enforceable in the SIP. The commenter points to Section 4.1 of the U.S. EPA July 2021 Clarification Memo (comment letter page 5, comment 10).

Response: Section 4.1 of the U.S. EPA July 2021 Clarification Memo suggested that states include certain information to determine when existing measures are necessary for reasonable progress. Briefly, the memo suggested that states should evaluate past implementation of existing measures and historical emission rate, projected emissions and emission rate, and enforceable limits/requirements related to the existing control measures. The memo stated that this information may be helpful to inform the expected future operations of the source (i.e., consistent historical operations suggests that future operations will also be consistent) alongside the existence of enforceable requirements that reflect the source's existing measures.

The MPCA, in the paragraph following table 32 in the draft SIP, acknowledged the information in Section 4.1 of the memo. Section 2.3.5 of the draft Regional Haze SIP contains this information for each of the facilities discussed, and based on the information provided in Section 2.3.5, MPCA stated that these sources with effective controls do not require additional measures to continue making reasonable progress and do not need enforceable emission limits in the SIP to hold emissions to a certain level (see Section 2.5.6 of the draft Regional Haze SIP).

Comment 87. The commenter points to Table 49 in the draft Regional Haze SIP, which contains permitted NO_X and SO_2 emission rates, actual NO_X and SO_2 emission rates, and the design heat input capacity of various emission units, and requests that MPCA expound on the information contained in this table to indicate if MPCA is determining that existing controls at these facilities are not necessary for reasonable progress. The commenter requested that MPCA indicate if it is making this determination. If so, the commenter requested MPCA point to the information in the SIP that supports that determination, or if not, suggesting that MPCA consider analyzing existing controls for these emission units for potential upgrades or optimization, pointing to Section 4.1 of U.S. EPA's July 2021 Clarification Memo (comment letter page 5-6, comment 11).

Response: The MPCA did not determine whether the existing controls for the emission units and facilities identified in Table 49 are necessary for reasonable progress. While MPCA did not specifically request that facilities evaluate existing controls for potential upgrades or optimization, U.S. EPA's August 2019 Guidance recognizes that there is no statutory or regulatory requirement to consider any particular measures.[30] The MPCA may consider evaluating existing controls at these facilities for potential upgrades or optimizations in future progress reports and/or implementation periods.

Additionally, Section 4.1 of U.S. EPA's July 2021 Clarification memo points to the use of existing controls measures to ensure existing sources do not increase their emissions inconsistent with reasonable progress.[31] The MPCA did address emissions from existing sources affecting reasonable progress through establishing new emission reduction targets for facilities located in Northeast Minnesota, which includes five of the eight facilities identified in Table 49. As referenced in Section 2.5.7 of the draft Regional Haze SIP, these new emission reduction targets allow MPCA to account for emissions from new or modified facilities to ensure that visibility conditions don't worsen and serves as a trigger of sorts that leads to considering/implementing additional, potentially more aggressive, emission reduction measures as part of the 2025 progress report or the 2028 comprehensive update.

Comment 88. The commenter referenced the discussion in Section 2.5.1 of the draft Regional Haze SIP for Southern Minnesota Beet Sugar Cooperative and the discussion in Table 82 (FLM consultation comments and MPCA response). The commenter suggested that it would be helpful if MPCA mentioned the decision to consider reevaluating this facility as part of the 2025 progress report or the 2028 comprehensive update (comment letter page 6, comment 12).

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[30] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 28-29.
[31] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 8-10

Response: The MPCA added additional language for Southern Minnesota Beet Sugar Cooperative to Section 2.5.1 to identify that MPCA will consider reevaluating this facility and emission unit in future progress reports and/or implementation periods.

Comment 89. The commenter raised questions regarding whether the controls identified in Section 2.5.1 for Southern Minnesota Beet Sugar Cooperative have been determined by MPCA to be necessary for reasonable progress. The commenter points to the summary of emission reduction measures necessary to make reasonable progress in Section 2.5.8 and that the NO_X control measures described previously for Southern Minnesota Beet Sugar are not identified in this section.

The commenter requested that MPCA better clarify whether controls at this facility will be required and if they are part of Minnesota's long-term strategy in this implementation period (comment letter page 6-7, comment 13).

Response: The MPCA added additional clarification to Section 2.5.8 to identify that MPCA determined the NO_X controls were necessary to continue making reasonable process, but has not reached an agreed path forward with the facility to install the identified NO_X controls. The NOx controls are not included in the summary of Minnesota's long-term strategy since MPCA has been unable to make these controls enforceable at this time. If an agreed path forward is reached, MPCA will supplement this Regional Haze SIP with the relevant information. If an agreed path forward is not reached, MPCA will consider reevaluating this facility and emission unit as part of the 2025 progress report or the 2028 comprehensive update.

Comment 90. The commenter questions whether the value of 6.6 dv should be 6.5 dv in Section 2.6.2, Table 64. (Comment letter page 7, comment 14)

Response: The value 6.6 dv (6.5 + 0.1 dv) is correct. The MPCA directs the commentor to Section 2.6.2, paragraph referencing Table 65, and to Appendix A. MPCA's Regional Haze Technical Support Document, Section 4.8.2, paragraph referencing Table 25 (final version), which now state, "*In the first implementation period, the 2028 projection on the clearest days at Boundary Waters was 6.6 dv, 0.1 dv above the goal of no degradation, 6.5 dv.*"

Comment 91. The commenter requested MPCA add the same conclusion from Table 65 in the main document to Table 24 in the Technical Support Document, Appendix A. Specifically, the words "…suggesting that visibility conditions will improve more than predicted." (Comment letter page 7-8, comment 15)

Response: The MPCA has revised Appendix A, MPCA's Regional Haze Technical Support Document, Section 4.8 to state, "*Not all emission reduction measures could be reflected in the modeling, and some emissions increase projections reflected in the modeling are unlikely to occur, suggesting visibility conditions will improve more than predicted*."

Comment 92. The commenter requested that MPCA explain how it determined which states were reasonable contributing states for purpose of consultation in Section 2.9.1 of the Regional Haze SIP. The commenter also requested that MPCA provide copies of the various communications documenting the consultation (comment letter page 8, comment 16).

Response: The MPCA explains how it determined which states were expected to reasonably contribute to visibility impairment at Minnesota Class I areas in Section 2.2.3 of the Regional Haze SIP. The MPCA added additional information to Section 2.9.1 to direct the reader to where they can find this information. The MPCA originally read the requirement in 40 CFR § 51.308(f)(2)(ii)(C) regarding, "*All substantive consultations must be documented"* as requiring States to document the interactions as

MPCA has done in Section 2.9.1 of the Regional Haze SIP. The MPCA has created Appendix I. Interstate Consultation Documentation to include the requested communications.

Comment letter 7 - Coalition to Protect America's National Parks (Coalition), Environmental Law and Policy Center (ELPC), Minnesota Center for Environmental Advocacy (MCEA), National Parks Conservation Association (NPCA), and Sierra Club

Comment 93. The commenter stated that Minnesota's proposed SIP will not result in reasonable progress toward improving visibility at the Class I areas its sources impact and summarized the comments that follow in their letter (comment letter page 2).

Response: The MPCA addresses the commenter's summarized comments in MPCA's response to Comment 96 through Comment 118.

Comment 94. The commenter stated that though they think there are improvements that need to be made to the SIP, they would like to thank MPCA for proposing a technically sound regional haze plan for this planning period. The commenter stated that MPCA had a robust source selection process, rejected international endpoint adjustments, use a good initial screening cost threshold, and committed to working with the FLMs throughout the consultation process (comment letter page 3).

Response: Comment noted.

Comment 95. The commenter provided an introduction summarizing the history of visibility protection provisions in the Clean Air Act regarding national parks and wilderness areas, the creation of the regional haze program, and what a regional haze SIP must provide under the requirements of the regional haze rules. The commenter also identifies the emission sources covered in their comments, the Class I areas of interest to the commenter, and a narrative summary of the benefits of implementing the regional haze requirements beyond reducing visibility impairment (comment letter page 6, section I).

Response: The MPCA believes the commenter provided these details as background information to support comments made later in their letter. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Comment 96. The commenter provided a summary of the Clean Air Act's visibility provisions and the Regional Haze Rule, U.S. EPA's 2017 revisions to the Regional Haze Rule, and U.S. EPA's July 8, 2021, Regional Haze Clarification Memorandum. The commenter stated, referencing the clarification memo, that MPCA has not met the requirements of the Regional Haze Rule and has avoided emission reductions by stating reductions are not necessary because visibility has improved, because reductions are anticipated at a later date or due to implementation of another program, or because a source has some level of control (comment letter page 7-10, section II. A, B, and C).

Response: The MPCA disagrees with the commenter. The draft Regional Haze SIP, and supporting analyses and documentation contained within, was created to address the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The MPCA references throughout the draft Regional Haze SIP where the decisions and analyses are based on the Regional Haze Rule requirements and U.S. EPA guidance.

While the commenter suggested MPCA has determined reductions are not necessary because visibility has improved, MPCA states in Sections 2.4.7 and 2.5.7 of the draft Regional Haze SIP that it did not consider the visibility benefits of individual control measures alongside the four statutory factors when evaluating emission control measures. The MPCA evaluated control measures, without consideration of current visibility conditions, through consistently applying the four statutory factors to determine which measures are needed to make reasonable progress. While the current visibility conditions have improved since the first implementation period in Minnesota Class I areas, that fact had no bearing on MPCA's determination of whether individual control measures were needed to continue making reasonable progress.

The MPCA's decision to remove sources from further analysis due to reductions anticipated at a later date or due to the implementation of other programs (i.e., future retirement dates) are based on the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The U.S. EPA specifically identifies that it may be reasonable for a state to not select a source with an expected shutdown/retirement prior to December 31, 2028, where there is an enforceable requirement to do so.[32] Therefore, MPCA did not require four-factor analyses for emission units with expected shutdown/retirements and established enforceable requirements for those shutdown/retirement dates.

The MPCA's decision to remove sources from further analysis based on the determination that they are effectively controlled is based on the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The U.S. EPA specifically identifies that it may be reasonable for a state to not select a source for further analysis when a state determines a source is effectively controlled with existing emission control measures. As identified in Section 2.3.5 of the draft Regional Haze SIP, the NO_X and SO_2 emission controls and associated limits are similar to examples, identified by the U.S. EPA in its August 2019 Guidance, where it may be reasonable to not select a source for further analysis (i.e., an emission unit that went through a BACT review).[33]

Comment 97. The commenter provided a summary of Minnesota's first implementation period regional haze SIP, U.S. EPA's review and approval with partial disapproval of Minnesota's SIP, the FIPs issued by U.S. EPA in response to the portions of Minnesota's SIP that were disapproved, and a summary of Minnesota's draft second implementation period regional haze SIP. Regarding Minnesota's draft regional haze SIP, the commenter stated that, while they commend MPCA for its thorough analysis and evaluation of current visibility conditions, they question MPCA's methodologies for removing certain sources from the four-factor analysis process and relying on retirement of Electric Generating Unit (EGU) sources in the absence of enforceable agreements. The commenter also indicated that these comments are discussed in more detail later in their letter (comment letter page 10-12, section III).

Response: Comments surrounding the history of Minnesota's regional haze efforts are noted. The MPCA believes the commenter provided these details as background information to support comments made later in their letter. The MPCA addresses the comments that use these details throughout the responses to this commenter.

Regarding the comments concerning MPCA's removal of certain sources, U.S. EPA's August 2019 Guidance provides that a state is not required to evaluate all sources of emissions in each implementation period, which is consistent with the iterative planning process that is setup by the Regional Haze Rule.[34] As discussed in Section 2.3.3 through Section 2.3.5 of the draft Regional Haze SIP, MPCA describes how it determined which initially selected sources were ultimately removed from the four-factor analysis process and how the removal of those sources was reasonable considering the factors described in U.S. EPA's August 2019 Guidance.

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32 *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 20.
33 *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.
34 *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 9.

The MPCA's decision to remove sources from further analysis due to reductions anticipated at a later date or due to the implementation of other programs (i.e., future retirement dates) are based on the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The U.S. EPA specifically identifies that it may be reasonable for a state to not select a source with an expected shutdown/retirement prior to December 31, 2028, where there is an enforceable requirement to do so.[35] Therefore, MPCA did not require four-factor analyses for emission units with expected shutdown/retirements and established enforceable requirements for those shutdown/retirement dates.

The MPCA addresses the commenter's more detailed comments on MPCA's methodology in MPCA's response to Comment 99 through Comment 111.

Comment 98. The commenter stated that MPCA did not respond to comments provided by the FLMs on the pre-public notice version of Minnesota's regional haze SIP and must do so by amending the SIP prior to submittal to U.S. EPA (comment letter page 12, section IV).

Response: The MPCA disagrees with the commenter. The MPCA responded to the comments provided by the FLMs on the pre-public notice of Minnesota's draft Regional Haze SIP as documented in Section 4.3 of the draft Regional Haze SIP.

Additionally, MPCA has meaningfully considered the FLMs input throughout the planning process for the second regional haze implementation period as documented in Section 2.9.2 of the draft Regional Haze SIP. For example, the FLMs input during the source selection process resulted in revisions to the sources MPCA selected for analysis as documented in Section 2.3.6 of the draft Regional Haze SIP.

Comment 99. The commenter stated that MPCA failed to follow the requirements of the Regional Haze Rule by not conducting four-factor analyses for the taconite facilities, the report attached to the commenter's letter and the consultation comments from the U.S. NPS demonstrate that there are cost-effective controls for these sources, MPCA ignored U.S. EPA's directive to evaluate SCR for the taconite sources, and that MPCA's justification for not conducting four-factor analyses for these sources was flawed. The commenter stated that MPCA must not rely on ongoing litigation between U.S. EPA and the Minnesota taconite facilities, assertions that the sources are effectively controlled, or U.S. EPA's BART determinations. The commenter provided further details in following subsections (comment letter page 12-13, section V).

Response: The MPCA disagrees with the commenter. As discussed in the response to Comment 97, MPCA points to the recommendations described in U.S. EPA's August 2019 Guidance for the source selection process. The MPCA added additional text to Sections 2.3.4, 2.3.5, and 2.4.8 of the draft Regional Haze SIP to inform the reader how the Taconite FIP, and ongoing negotiations between U.S. EPA and the Minnesota taconite facilities, were evaluated as part of the decision to not select these sources for an analysis of control measures in this implementation period.

While MPCA did not evaluate SCR for the taconite sources in this implementation period, MPCA found it was reasonable to do so given the circumstances surrounding the Taconite FIP. The potential that the applicable emission limits in the Taconite FIP could change highlights the sensitivity of the outcome of any four-factor analyses that could be conducted for these facilities at this time. As the baseline emission rate, used as the starting point for a four-factor analysis, could change depending on the outcome of the settlement discussions, so could any decisions on what emission control measures are cost-effective and necessary to make reasonable progress after identifying the relevant factors. This also informed MPCA's decision to not select these sources for an analysis of control measures in this

[35] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 20.

implementation period to distribute the analytical work needed for the regional haze program across multiple implementation periods.

The MPCA's decision to remove sources from further analysis based on the determination that they are effectively controlled is based on the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The U.S. EPA specifically identifies that it may be reasonable for a state to not select a source for further analysis when a state determines a source is effectively controlled with existing emission control measures. As identified in Section 2.3.5 of the draft Regional Haze SIP, the NO_X and SO_2 emission controls and associated limits established by the Taconite FIP are similar to examples, identified by the U.S. EPA in its August 2019 Guidance, where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[36]

Comment 100. The commenter stated the taconite facilities are generally among the highest Q/d values for Minnesota's Class I areas and provided the emissions, distance to Minnesota Class I areas, and Q/d value for the taconite facilities in tables using the information provided in the draft Regional Haze SIP (comment letter page 13-14, section V.A).

Response: The MPCA believes the commenter provided these details as background information to support comments made later in their letter. The MPCA acknowledges that the Q/d values for the Minnesota taconite facilities are among the highest values for sources in the state. The MPCA addresses the comments that use these details in MPCA's response to Comment 101 through Comment 105.

Comment 101. The commenter pointed to U.S. EPA's August 2019 Guidance and stated that MPCA has not provided sufficient information to determine that the emission units at Minnesota taconite facilities are effectively controlled. The commenter includes a table summary of MPCA's determination of effectively controlled emission units at taconite facilities from the draft Regional Haze SIP, stated that MPCA was wrong to rely on U.S. EPA's BART determinations in the Taconite FIP to exclude the taconite sources from further analysis, and requests that MPCA require four-factor analyses from the taconite sources and include NO_X and SO_2 emission limits in the Regional Haze SIP prior to submittal to U.S. EPA (comment letter page 14-17, section V.B).

Response: As discussed in MPCA's response to Comment 99, MPCA points to the recommendations described in U.S. EPA's August 2019 Guidance for the source selection process. The MPCA added additional text to Sections 2.3.4, 2.3.5, and 2.4.8 of the draft Regional Haze SIP to inform the reader how the Taconite FIP, and ongoing negotiations between U.S. EPA and the Minnesota taconite facilities, were evaluated as part of the decision to not select these sources for an analysis of control measures in this implementation period.

The potential that the applicable emission limits in the Taconite FIP could change highlights the sensitivity of the outcome of any four-factor analyses that could be conducted for these facilities at this time. As the baseline emission rate, used as the starting point for a four-factor analysis, could change depending on the outcome of the settlement discussions, so could any decisions on what emission control measures are cost-effective and necessary to make reasonable progress after identifying the relevant factors. This also informed MPCA's decision to not select these sources for an analysis of control measures in this implementation period to distribute the analytical work needed for the regional haze program across multiple implementation periods.

[36] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.

The MPCA's decision to remove sources from further analysis based on the determination that they are effectively controlled is based on the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The U.S. EPA specifically identifies that it may be reasonable for a state to not select a source for further analysis when a state determines a source is effectively controlled with existing emission control measures. As identified in Section 2.3.5 of the draft Regional Haze SIP, the NO_X and SO_2 emission controls and associated limits established by the Taconite FIP are similar to examples, identified by the U.S. EPA in its August 2019 Guidance, where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[37]

MPCA will consider reevaluating these facilities and emission units, and the idea raised by the U.S. NPS in Comment 45 regarding an integrated approach to evaluating emission control strategies, in future progress reports and/or implementation periods.

Comment 102. The commenter stated that MPCA must not rely on the ongoing negotiations between U.S. EPA and the Minnesota taconite facilities to exempt the facilities from preparing four-factor analyses and controls for this regional haze implementation period (comment letter page 17-18, section V.C).

Response: The MPCA disagrees with the commenter's characterization that MPCA has relied on the ongoing negotiations to exempt the Minnesota taconite facilities from preparing four-factor analyses. The Minnesota taconite facilities were not removed from the four-factor analysis process solely due to the presence of ongoing litigation as the commenter suggests while pointing to a letter from U.S. EPA to the state of Wyoming. The MPCA considered additional information as part of removing the Minnesota taconite facilities from further analysis such as MPCA's effectively controlled determination based on the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo and the potential that the applicable emission limits in the Taconite FIP could change and effect any decisions on what emission control measures are cost-effective and necessary to make reasonable progress.

The MPCA has provided a reasonable explanation for excluding these facilities from the four-factor analysis process in this implementation period as the quoted portion of U.S. EPA's letter to Wyoming suggests. See also MPCA's response to Comment 99.

Comment 103. The commenter stated that there is confusion regarding the current Taconite FIP requirements and the applicable deadlines for compliance and requested that MPCA lay out the current Taconite FIP requirements and associated deadlines. The commenter requested that MPCA address the current FIP emission limits, whether they have been achieved, and MPCA's use of those limits in the estimated NO_X emission reductions included in the modeling for 2028 reasonable progress goals (comment letter page 18, section V.D).

Response: The MPCA provided a summary of the current Taconite FIP requirements in Section 1.3 of the draft Regional Haze SIP including that the requirements of the Taconite FIP apply as currently promulgated. For clarity, MPCA has added a table to Section 1.3 to provide a summary of the currently promulgated emission limits contained in the Taconite FIP for Minnesota taconite facilities and the associated compliance dates that were provided by U.S. EPA staff to MPCA in a February 12, 2020, email.

[37] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.

While the compliance dates for the applicable emission limits have passed for all Minnesota taconite facilities at this time, MPCA believes it is reasonable to assume that U.S. EPA and the taconite facilities will reach settlement agreements that finalize the requirements of the Taconite FIP prior to 2028 (the year of emissions projections modeled).

See also MPCA's response to Comment 85 regarding the use of the Taconite FIP emission limits for emissions projections to 2028.

Comment 104. The commenter referenced comments by U.S. EPA in the April 12, 2016, final rule issued for the Taconite FIP and comments by the U.S. NPS regarding the evaluation of SCR with reheat as a potential option for making reasonable progress. The commenter requested that MPCA evaluate SCR with reheat for controlling NO_X emissions.

The commenter also referenced comments from the U.S. NPS regarding the recommendation to evaluate an integrated approach to reduce regional haze pollutants from taconite facilities and MPCA's response to those consultation comments. The commenter stated that MPCA failed to reschedule the start of the public notice to address this comment from the U.S. NPS and failed to respond to the U.S. NPS evaluation of SCR with reheat for United Taconite. The commenter requested that MPCA respond to all the U.S. NPS comments (comment letter page 18-19, section V.E).

Response: Regarding the evaluation of SCR with reheat for taconite sources, see MPCA's response to Comment 99. Regarding the comments provided by the U.S. NPS on the pre-public notice version of the draft Regional Haze SIP in general, see MPCA's response to Comment 98.

Additionally, the requirements regarding FLM consultation identified in 40 CFR § 51.308(i)(2) do not require states to restart public notice to accommodate particular comments. The MPCA met the consultation requirements of 40 CFR § 51.308(i)(2), including providing the pre-public notice draft Regional SIP materials far enough in advance of the public notice start and public meeting. The MPCA responded to the FLM consultation comments as documented in Section 4.3 of the draft Regional Haze SIP, including the FLM comment concerning SCR with reheat for United Taconite. The MPCA has responded to all of U.S. NPS comments, many of which are similar to, or the same as, their comments submitted during the consultation period (see MPCA's responses to Comment 4 through Comment 51).

Comment 105. The commenter requested that MPCA evaluate controls for other emission units at Northshore Mining - Silver Bay and U.S. Steel - Minntac.

Regarding Northshore Mining - Silver Bay, the commenter stated that the administrative order for the facility's power boilers doesn't contain the enforceable provisions needed to remove the emission units from the four-factor analysis process, as the administrative order doesn't establish an enforceable requirement to permanently cease operations or establish control requirements if the facility restarts either boiler. The commenter requested that MPCA require the facility to conduct four-factor analyses for these boilers and establish controls for this version of the Regional Haze SIP.

Regarding U.S. Steel - Minntac, the commenter stated that the draft Regional Haze SIP failed to analyze emissions from the heating boilers and stationary internal combustion engines at the facility. The commenter provided potential to emit calculations for the boilers base on the PM and SO_2 emission limits for the boilers identified in the facility's permit. The commenter also identified the SO_2 emission limits for stationary internal combustion engines and requested that MPCA evaluate controls for these engines (comment letter page 20-22, section V.F).

Response: Regarding the boilers at Northshore Mining - Silver Bay, MPCA disagrees with the commenter's opinion that the administrative order for the boilers does not contain enforceable provisions for removing the emission units from the four-factor analysis process. The administrative order establishes the expected operations of the boiler through 2031 and what is required of the facility if the boilers restart prior to 2031, including preparing an updated four-factor analysis of NO_X and SO_2 controls for the boilers. Additionally, MPCA also evaluated the four-factor analyses prepared for the boilers and revised the projected future emissions while contemplating what would happen if the boilers resumed operations prior to the anticipated 2031 termination of the power supply agreement with Minnesota Power.

Regarding the emission units identified at U.S. Steel - Minntac, the requirements of the Regional Haze Rule do not require states to evaluate all sources of pollutants at a facility. Furthermore, the commenter has calculated potential emissions for the identified emission units using emission limits (e.g., lb/MMBtu) and design capacity information (e.g., MMBtu/hr) identified in the facility's permit, rather than using recent years of actual emissions data as recommended by the U.S. EPA in its August 2019 Guidance. The indurating furnaces at U.S. Steel - Minntac represent the vast majority of NO_X and SO_2 emissions from the stationary source as a whole. For example, in 2020 the indurating furnaces were responsible for 98% of total facility NO_X emissions (5,846 tons NO_X from the furnaces compared to 5,963 tons NO_X facility wide) and nearly 100% of total facility SO_2 emissions (903.8 tons SO_2 from the furnaces compared to 904.2 tons SO_2 facility wide). Furthermore, most PM emissions come from material handling operations at the facility. As described in Section 2.1 and 2.3.1 of the draft Regional Haze SIP, MPCA focused on evaluating sources of SO_2 and NO_X emissions in this implementation period as opposed to other pollutants that comparably make up only a small contribution to visibility impairment.

Comment 106. The commenter stated that MPCA has not established enforceable requirements for Xcel Energy - Sherburne Generating Plant's Units 1 and 2. The commenter points to the Unit 1 and 2 retirement date requirements included in the facility's permit and states that those requirements are not sufficient for enforceability. The commenter states that the reliance on these permit requirements is inconsistent with the Regional Haze Rules and U.S. EPA guidance, as they are not permanent requirements or included in Minnesota's SIP. The commenter requests that MPCA make the retirement dates for Units 1 and 2 enforceable via an administrative order or instead include a four-factor analysis of controls for these units alongside Unit 3 at the facility (comment letter page 22-24, section VI.A).

Response: The MPCA disagrees with the commenter. Air emission permits issued in Minnesota are enforceable documents that MPCA can act on if a facility is in noncompliance just as MPCA can act on an administrative order if the facility is in noncompliance. Furthermore, the draft Regional Haze SIP identifies the retirement dates and identifies those retirements as emission reduction measures necessary to make reasonable progress. Identifying these retirements and proposing them as part of Minnesota's long-term strategy includes them in the SIP, making them permanent and unable to be revised without a U.S. EPA-approved SIP revision.

The MPCA's decision to remove sources from further analysis due to reductions anticipated at a later date or due to the implementation of other programs (i.e., future retirement dates) are based on the requirements of the Regional Haze Rule and the recommendations for states found in the U.S. EPA August 2019 Guidance and July 2021 Clarification Memo. The U.S. EPA specifically identifies that it may be reasonable for a state to not select a source with an expected shutdown/retirement prior to December 31, 2028, where there is an enforceable requirement to do so.[38] Therefore, MPCA did not require four-factor analyses for emission units with expected shutdown/retirements and established enforceable requirements for those shutdown/retirement dates.

Comment 107. The commenter stated that MPCA's administrative order that establishes the retirement date for Xcel Energy - Sherburne Generating Plant's Unit 3, is dependent on the Minnesota Public

[38] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 20.

Utilities Commission (MN PUC) approval of the facility's integrated resource plan. Because the MN PUC approved the plan MPCA should include the retirement of Unit 3 as a permanent and enforceable term of the Regional Haze SIP. The commenter also stated that MPCA improperly relies on the retirement of Unit 3 since the 2030 retirement date does not occur before the end of 2028.

The commenter also stated that MPCA erred when excluding Units 1, 2, and 3 at the facility from the four-factor analysis process and pointed to 40 CFR § 51.308(f)(2)(i) to state that MPCA is obligated to consider whether there are control measures that could be implemented even where there is an enforceable closure date. The commenter provided suggestions for NO_X and SO_2 emission reductions and requests that MPCA require four-factor analyses for these units (comment letter page 24-26, section VI.B).

Response: The MPCA is not the only entity with regulatory oversight for the facility and included language in the administrative order recognizing that the MN PUC had regulatory oversight over the future operations of this facility as well. As the commenter notes, the integrated resource plan was approved so the language included in MPCA's administrative order does not apply and the identified retirement date of Unit 3 stands. Furthermore, the draft Regional Haze SIP identifies the retirement dates and identifies those retirements as emission reduction measures necessary to make reasonable progress. Identifying these retirements and proposing them as part of Minnesota's long-term strategy includes them in the SIP, making them permanent and unable to be revised without a U.S. EPA-approved SIP revision.

Regarding the commenter's position that MPCA erred by not evaluating Units 1, 2, and 3 at the facility, MPCA disagrees. The U.S. EPA specifically identifies that it may be reasonable for a state to not select a source with an expected shutdown/retirement prior to December 31, 2028, where there is an enforceable requirement to do so.[39] Additionally, U.S. EPA's August 2019 Guidance identifies that the year 2028 is not a bright line for retirement dates when not selecting a source for analysis when there is a requirement for the source to cease operation by a date after 2028.[40] Therefore, MPCA did not require four-factor analyses for these units.

Comment 108. The commenter stated that MPCA determined that Units 3 and 4 at Minnesota Power - Boswell Energy Center were effectively controlled based on recent actual emissions and erred when it exempted these units from the four-factor analysis process since neither the permit nor SIP make those recent emission levels enforceable. The commenter stated that the MCPA should have evaluated the replacement of the existing SNCR with SCR for Unit 4. The commenter requested that MPCA either require four-factor analyses for these units or include in the SIP the SO_2 emission rates that the units are achieving (comment letter page 26-28, section VI.C).

Response: The MPCA disagrees with the commenter and would like to clarify that while recent emission rates were provided, that was not the reason these units were determined to be effectively controlled. As identified in Section 2.3.5 of the draft Regional Haze SIP, the NO_X and SO_2 emission controls and associated limits are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis, an emission unit that went through a BACT review, and/or EGUs with add-on FGD that meet the applicable SO_2 limits of the MATS rule).[41] Therefore, Units 3 and 4 are not required to undergo

[39] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 20.
[40] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 20.
[41] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.

a four-factor analysis and any additional requirements that may have resulted from a four-factor analysis do not need to be considered at this time.

The information provided regarding recent emission levels for these units was included to address Section 4.1 of the U.S. EPA July 2021 Clarification Memo, which suggests that states should include certain information to determine when existing measures are necessary for reasonable progress. The memo states that this information may be helpful to inform the expected future operations of the source (i.e., consistent historical operations suggests that future operations will also be consistent), alongside the existence of enforceable requirements that reflect the source's existing measures. Based on the information provided in Section 2.3.5, MPCA stated that these sources with effective controls do not require additional measures to continue making reasonable progress in Section 2.5.6 of the draft Regional Haze SIP. Therefore, MPCA did not require four-factor analyses for these units nor establish recent SO_2 emission rates as enforceable limits. The MPCA will consider reevaluating these emission units in future progress reports and/or implementation periods.

Comment 109. The commenter stated that the four-factor analyses for the Virginia Department of Public Utilities were flawed for two reasons.

First, the facility failed to analyze that Boiler 11 would likely be exclusively fired with natural gas versus wood and did not analyze low NO_X burners as a control option given the facility-indicated future operations. The commenter requested that MPCA should evaluate the NO_X emission rates when burning natural gas to determine appropriate NO_X controls and emission limits for the boiler.

Second, the commenter stated that MPCA did not require a four-factor analysis for Boilers 10, 12, and 13 at the facility nor explain why it did not require four-factor analyses for these boilers. The commenter requested that MPCA require four-factor analyses for these boilers (comment letter page 28, section VI.D).

Response: The MPCA disagrees with the comment that suggests MPCA did not analyze low NOx burners as a control option, and requests that MPCA evaluate NOx emissions to determine controls and limits for Boiler 11. The MPCA would like to note that the boiler has different burners to accommodate the different fuel types. As identified in the four-factor analysis, the natural gas burners were permitted and installed in 2015 to assist in stabilizing combustion due to efficiency changes caused by the moisture content of the wood fuel. The natural gas burners have a design capacity heat input rate of 140 MMBtu/hr versus the 230 MMBtu/hr design capacity heat input rate of the boiler. As identified in the four-factor analysis, the natural gas burners on Boiler 11 are low NO_X burners. If the boiler was operated using only natural gas at the maximum firing rate, the estimated NO_X emission rate would be 0.09 lb/MMBtu using default U.S. EPA emission factors.

Regarding Boiler 10, the highest annual emissions reported for Boiler 10 from 2016 through 2020 were 12.3 tons NO_X and 0.12 tons SO_2 in 2017. Based on the annual emissions for Boiler 10, MPCA would not have evaluated this boiler as part of the four-factor analyses in this implementation period as MPCA estimates a low likelihood that the outcome of a control measure analysis would result in a determination of feasible controls. This should not be construed to mean that MPCA has made the determination that there are no feasible controls for this unit.

Regarding Boilers 12 and 13, MPCA did not evaluate these boilers as part of the four-factor analyses in this implementation period because the facility received a permit and authorization to construct these boilers in March 2021 (see Air Emissions Permit No. 13700028-102), approximately only 4 months before the July 2021 due date of the comprehensive update to Minnesota's Regional Haze SIP. Additionally, Boilers 12 and 13 each have a design heat input capacity of 60.78 MMBtu/hr and the manufacturer-provided NO_X emission rate is 0.035 lb/MMBtu, equivalent to roughly 9 tons per year of

NO_X emissions from each boiler individually if they operate 8,760 hours per year. Based on the annual emissions for Boiler 12 and 13, MPCA would not have evaluated these boilers as part of the four-factor analyses in this implementation period as MPCA estimates a low likelihood that the outcome of a control measure analysis would result in a determination of feasible controls. This should not be construed to mean that MPCA has made the determination that there are no feasible controls for these units.

Comment 110. The commenter stated that the NO_X limits MPCA included instead of a requirement to install SNCR on Boilers 1A, 2A, and 3A for Hibbing Public Utilities Commissions was legally inadequate for four reasons.

First, there were no proposed SO_2 emission limits for these boilers that emission rates closer to the actual emission rates. The commenter requested that MPCA amend the existing administrative order to require an SO_2 emission limit.

Second, that since MPCA determined that SNCR was cost-effective it should include that requirement in the final Regional Haze SIP instead of the mass-based NO_X emission limit.

Third, without a continuous emission monitor system (CEMS) for NO_X emissions, the NO_X limits in the administrative order are unenforceable and don't provide for reductions on a continuous basis. The commenter requested that MPCA shorten the limits to a shorter timeframe.

Fourth, the administrative order does not prohibit coal use in the boilers. The commenter stated that in order for the facility to use mass-based emission limits, instead of emission controls, they must forego the operational flexibility and prohibit coal use (comment letter page 29-30, section VI.E).

Response: Regarding SO_2 limits, MPCA determined that SO_2 controls were not cost-effective during this regional haze implementation period and, as a result, did not propose any SO_2 emission limits like it did as an alternative to the cost-effective NO_X controls that were identified. As documented in Section 2.5.1, MPCA used a $10,000 per ton initial screening threshold to determine which control measures to focus on in the review of four-factor analyses. Application of SO_2 controls on the boilers at these facilities was above the initial screening threshold, so the control measures did not carry through to later parts of the analysis.

Regarding NO_X emissions and controls, MPCA identified the proposed strategy since the expected future operations of the boilers were expected to differ from historical operating practices. The NO_X emission limits provided the equivalent level of control, to the controls determined to be cost-effective under historical operating practices, while accommodating the facility's proposed changes to operating practices moving forward. The portion of U.S. EPA's August 2019 guidance that the commenter references points to circumstances where a state has determined operation of the control equipment is necessary when it is "independent of the forecasted operating level." This is not the circumstance identified here, as the determination that NO_X controls were necessary to make reasonable progress was dependent on the boilers continuing to combust coal under historical operating conditions. As documented in the administrative order for this facility, and in Section 2.5.1 of the draft Regional Haze SIP, projected future operations of the facility differ significantly from the historical operations. Therefore, the MPCA did not revise the SIP to include requirements to install and operate SNCR controls for these boilers.

Furthermore, MPCA disagrees with the commenter regarding the enforceability of the administrative order. The order contains requirements for calculating emissions from the boilers based on fuel type and usage. Alongside default emission factors from U.S. EPA or as determined via stack testing already required at the facility, the facility is able to demonstrate compliance with the required NO_X emission limits.

Regarding coal usage, the administrative order does not specifically prohibit coal usage, but the emission limit effectively reduces the total amount of coal that could be used. As the administrative order identifies, coal usage was intentionally allowed to allow the facility to combust it as a backup/emergency fuel, nor is there a requirement for an emission limit such as this one to require a certain fuel be prohibited. This also addresses the averaging time. While there is no specific requirement limiting NO_X emissions to a shorter averaging period, the NO_X emission rate will inherently be lower than historical operating practices as the facility moves to primarily combusting natural gas (~0.09 lb/MMBtu) versus coal (~0.52 lb/MMBtu).

Comment 111. The commenter stated that they support the U.S. NPS recommendation to install NO_X and SO_2 controls at American Crystal Sugar - Crookston, American Crystal Sugar - East Grand Forks, and Southern Minnesota Beet Sugar Cooperative. The commenter requested that MPCA include requirements for NO_X and SO_2 controls at these facilities in the final Regional Haze SIP (comment letter page 30, section VII).

Response: See MPCA's response to Comment 14, Comment 18 through Comment 22 regarding American Crystal Sugar - Crookston, Comment 23 through Comment 27 regarding American Crystal Sugar - East Grand Forks, and Comment 28 through Comment 33 regarding Southern Minnesota Beet Sugar Cooperative.

Comment 112. The commenter provided a summary of environmental justice considerations and information available on the MPCA's website and stated that MPCA failed to take environmental justice communities into consideration as it developed plans for Minnesota's Class I areas (comment letter page 31-32, section VIII).

Response: Although Regional Haze is a program focused on visibility in specific, federally designated geographic areas, MPCA works to include environmental justice across its programs. The MPCA conducted voluntary, additional outreach to tribal nations as part of developing this SIP, catalogued in Section 2.9.3 of the draft Regional Haze SIP. A summary of local benefits from emission reductions is now included in Section 3.2 of the Regional Haze SIP.

Comment 113. The commenter requested that MPCA evaluate the communities/counties impacted by the sources located in environmental justice areas across Minnesota (comment letter page 32, section VIII.A).

Response: Section 3.2 has been added to the Regional Haze SIP to show where local benefits from reductions would occur.

Comment 114. The commenter identified legal grounds for considering environmental justice in SIP submittals (i.e., specific case law that points to states submitting SIPs that are more stringent than federal law requires) and Executive Orders focused on environmental justice considerations for federal agencies. The commenter requested that MPCA consider environmental justice in its final Regional Haze SIP to facilitate U.S. EPA's compliance with the identified Executive Orders (comment letter page 32-33, section VIII.B).

Response: The Regional Haze program is specifically geared towards improving visibility in Class I areas. The current rules and guidance do not have specific weighting or criteria to require reductions for non-visibility impacts or impacts to environmental justice communities. The MPCA would support future EPA rulemakings to refine environmental justice considerations within this program.

Although Regional Haze is a program focused on visibility in specific, federally designated geographic areas, MPCA works to include environmental justice across its programs. The MPCA conducted voluntary, additional outreach to tribal nations as part of developing this SIP, catalogued in Section 2.9.3 of the draft Regional Haze SIP. A summary of local benefits from emission reductions is now included in Section 3.2 of the Regional Haze SIP.

Comment 115. The commenter pointed to U.S. EPA's August 2019 Guidance; July 2021 Clarification Memo; and various U.S. EPA policies, guidance, directives, and other material that refer to environmental justice. The commenter requested that MPCA consider these sources of information in conducting a meaningful environmental justice analysis (comment letter page 33-34, section VIII. C and D).

Response: The Regional Haze program is specifically geared towards improving visibility in Class I areas. The current rules and guidance do not have specific weighting or criteria to require reductions for non-visibility impacts or impacts to environmental justice communities. The MPCA would support future EPA rulemakings to refine environmental justice considerations within this program.

Although Regional Haze is a program focused on visibility in specific, federally designated geographic areas, MPCA works to include environmental justice across its programs. The MPCA conducted voluntary, additional outreach to tribal nations as part of developing this SIP, catalogued in Section 2.9.3 of the draft Regional Haze SIP. A summary of local benefits from emission reductions is now included in Section 3.2 of the Regional Haze SIP.

Comment 116. The commenter stated that should U.S. EPA promulgate a FIP for Minnesota sources, it should integrate environmental justice considerations into its decision-making (comment letter page 34, section VIII.E).

Response: Comment noted.

Comment 117. The commenter stated that MPCA must consider environmental justice under Title VI of the Civil Rights Act and has an obligation to ensure the fair treatment of communities that have been environmentally impacted by sources of pollution. The commenter requested that the MCPA conduct an analysis of current and potential effects to communities from various emission sources (comment letter page 34-35, section VIII.F).

Response: The Regional Haze program is specifically geared towards improving visibility in Class I areas. The current rules and guidance do not have specific weighting or criteria to require reductions for non-visibility impacts or impacts to environmental justice communities. The MPCA would support future EPA rulemakings to refine environmental justice considerations within this program.

Although Regional Haze is a program focused on visibility in specific, federally designated geographic areas, MPCA works to include environmental justice across its programs. The MPCA conducted voluntary, additional outreach to tribal nations as part of developing this SIP, catalogued in Section 2.9.3 of the draft Regional Haze SIP. A summary of local benefits from emission reductions is now included in Section 3.2 of the Regional Haze SIP.

Comment 118. The commenter states that the draft Regional Haze SIP lacks consideration of environmental justice and failed to include enforceable emission limits for sources that impact environmental justice communities. The commenter also provided information, such as percentiles for low income, unemployment rate, and $PM_{2.5}$ and ozone indices from U.S. EPA's EJSCREEN, for populations and locations around certain facilities.

The commenter requested that MPCA consider all sources that impact these communities and establish emission limits that reduce impacts at Class I areas as well as environmental justice communities (comment letter page 35, section VIII.G).

Response: Comment noted. See Section 3.2 of the Regional Haze SIP for a summary of localized emission reduction benefits in areas of concern for environmental justice. The Regional Haze program is specifically geared towards improving visibility in Class I areas. The current rules and guidance do not have specific weighting or criteria to require reductions for non-visibility impacts or impacts to environmental justice communities. The MPCA would support future EPA rulemakings to refine environmental justice considerations within this program.

Minnesota State Register

Published every Monday (Tuesday when Monday is a holiday)

Proposed, Adopted, Emergency, Expedited, Withdrawn, Vetoed Rules; Executive Orders; Appointments; Commissioners' Orders; Revenue Notices; Official Notices; State Grants & Loans; State Contracts; Non-State Public Bids, Contracts and Grants

Monday 22 August 2022

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Minnesota State Register

Judicial Notice Shall Be Taken of Material Published in the Minnesota State Register

The Minnesota State Register is the official publication of the State of Minnesota's Executive Branch of government, published weekly to fulfill the legislative mandate set forth in Minnesota Statutes, Chapter 14, and Minnesota Rules, Chapter 1400. It contains:

- **Proposed Rules**
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Printing Schedule and Submission Deadlines

Vol. 47 Issue Number	Publish Date	Deadline for: all Short Rules, Executive and Commissioner's Orders, Revenue and Official Notices, State Grants, Professional-Technical- Consulting Contracts, Non-State Bids and Public Contracts	Deadline for LONG, Complicated Rules (contact the editor to negotiate a deadline)
#9	Monday 29 August	Noon Tuesday 23 August	Noon Thursday 11 August
#10	Tuesday 6 September	Noon Tuesday 30 August	Noon Thursday 18 August
#11	Monday 12 September	Noon Tuesday 6 September	Noon Thursday 25 August
#12	Monday 19 September	Noon Tuesday 13 September	Noon Thursday 1 September

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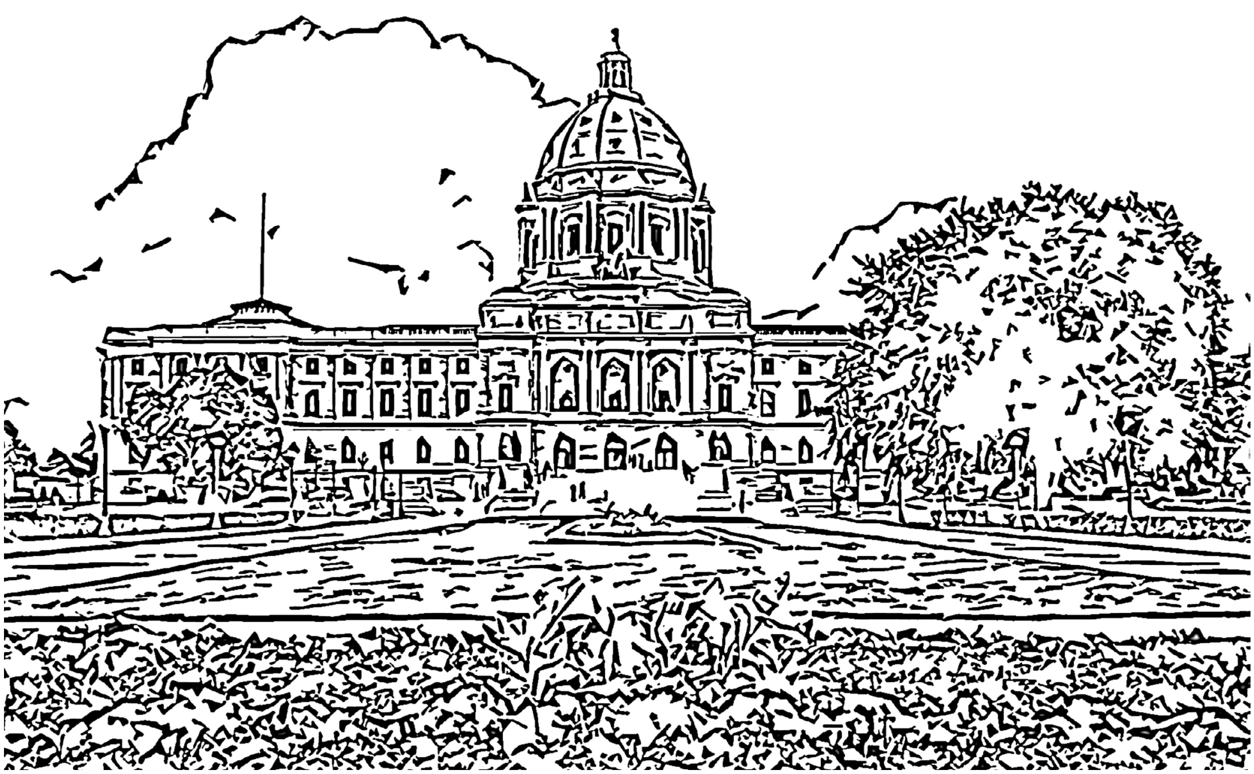

Minnesota Rules: Amendments and Additions

NOTICE: How to Follow State Agency Rulemaking in the State Register

The State Register is the official source, and only complete listing, for all state agency rulemaking in its various stages. State agencies are required to publish notice of their rulemaking action in the State Register. Published every Monday, the State Register makes it easy to follow and participate in the important rulemaking process. Approximately 80 state agencies have the authority to issue rules. Each agency is assigned specific Minnesota Rule chapter numbers. Every odd-numbered year the Minnesota Rules are published. Supplements are published to update this set of rules. Generally speaking, proposed and adopted exempt rules do not appear in this set because of their short-term nature, but are published in the State Register.

An agency must first solicit Comments on Planned Rules or Comments on Planned Rule Amendments from the public on the subject matter of a possible rulemaking proposal under active consideration within the agency (Minnesota Statutes §§ 14.101). It does this by publishing a notice in the State Register at least 60 days before publication of a notice to adopt or a notice of hearing, or within 60 days of the effective date of any new statutory grant of required rulemaking.

When rules are first drafted, state agencies publish them as Proposed Rules, along with a notice of hearing, or a notice of intent to adopt rules without a hearing in the case of noncontroversial rules. This notice asks for comment on the rules as proposed. Proposed emergency rules, and withdrawn proposed rules, are also published in the State Register. After proposed rules have gone through the comment period, and have been rewritten into their final form, they again appear in the State Register as Adopted Rules. These final adopted rules are not printed in their entirety, but only the changes made since their publication as Proposed Rules. To see the full rule, as adopted and in effect, a person simply needs two issues of the State Register, the issue the rule appeared in as proposed, and later as adopted.

The State Register features partial and cumulative listings of rules in this section on the following schedule: issues #1-26 inclusive (issue #26 cumulative for issues #1-26); issues #27-52 inclusive (issue #52, cumulative for issues #27-52 or #53 in some years). A subject matter index is updated weekly and is available upon request from the editor. For copies or subscriptions to the State Register, contact the editor at 651-201-3204 or email at sean.plemmons@state.mn.us

Volume 46 - Minnesota Rules

(Rules Appearing in Vol. 46 Issues #27-52 are in Vol. 46, #52 - Monday 27 June 2022)

Volume 47, #8

Tuesday 5 July 2022 - Monday 22 August

Exempt Rules

Exempt rules are excluded from the normal rulemaking procedures (*Minnesota Statutes* §§ 14.386 and 14.388). They are most often of two kinds. One kind is specifically exempted by the Legislature from rulemaking procedures, but approved for form by the Revisor of Statutes, reviewed for legality by the Office of Administrative Hearings, and then published in the State Register. These exempt rules are effective for two years only.

The second kind of exempt rule is one adopted where an agency for good cause finds that the rulemaking provisions of *Minnesota Statutes*, Chapter 14 are unnecessary, impracticable, or contrary to the public interest. This exemption can be used only where the rules:

(1) address a serious and immediate threat to the public health, safety, or welfare, or

(2) comply with a court order or a requirement in federal law in a manner that does not allow for compliance with *Minnesota Statutes* Sections 14.14-14.28, or

(3) incorporate specific changes set forth in applicable statutes when no interpretation of law is required, or

(4) make changes that do not alter the sense, meaning, or effect of the rules.

These exempt rules are also reviewed for form by the Revisor of Statutes, for legality by the Office of Administrative Hearings and then published in the *State Register*. In addition, the Office of Administrative Hearings must determine whether the agency has provided adequate justification for the use of this exemption. Rules adopted under clauses (1) or (2) above are effective for two years only. The Legislature may also exempt an agency from the normal rulemaking procedures and establish other procedural and substantive requirements unique to that exemption.

KEY: Proposed Rules - Underlining indicates additions to existing rule language. ~~Strikeouts~~ indicate deletions from existing rule language. If a proposed rule is totally new, it is designated "all new material." **Adopted Rules** - Underlining indicates additions to proposed rule language. ~~Strikeout~~ indicates deletions from proposed rule language.

Department of Labor and Industry

Occupational Safety and Health Division

Proposed Exempt Permanent Rules Adopting an Occupational Exposure to COVID-19 Standard; Request for Comments

NOTICE IS HEREBY GIVEN that the Department of Labor and Industry, Occupational Safety and Health Division (Minnesota OSHA) proposes to adopt the following revisions to the Department of Labor and Industry, Occupational Safety and Health Rules, as authorized under Minnesota Statutes §182.655. This notice proposes the adoption of Occupational Safety and Health Standards already proposed and adopted by the Federal Occupational Safety and Health Administration (Federal OSHA).

All interested or affected persons have 30 days from the date this notice is published in the *State Register* to submit, in writing, data and views on the proposed amendments to the rule. Comments are encouraged, including comments supporting or opposing the proposed amendments. Each comment should identify the portion of the proposed amendment addressed, the reason for the comment, and any proposed change.

Any person may file with the Commissioner written objections to the proposed amendments stating the grounds for those objections and may request a public hearing. A public hearing will be held if 25 or more persons submit written requests for a public hearing on the proposed amendments within the 30-day comment period. Requests for hearing must include the name and address of the person submitting the request, define the reasons for the request, and discuss any proposed changes. If a public hearing is required, the Department will proceed according to the provisions of Minnesota Statutes §182.655 and Minnesota Rules 5210.0020 to 5210.0100.

Written comments or requests for a public hearing should be sent to: Occupational Safety and Health Division, Department of Labor and Industry, 443 Lafayette Road, St. Paul, Minnesota 55155-4307.

Nicole Blissenbach
Temporary Commissioner

SUMMARY OF CHANGES

The following is a brief and partial summary of the proposed amendments. To review the complete *Federal Register* notice referenced below, visit ***www.osha.gov***.

(A) "Occupational Exposure to COVID-19, Emergency Temporary Standard" On June 21, 2021, Federal OSHA published an Emergency Temporary Standard (ETS) for COVID-19 in the Federal Register, to protect workers providing healthcare or healthcare support services. On December 27, 2021 Federal OSHA announced that it was withdrawing the non-recordkeeping portions of the healthcare ETS, while keeping the COVID-19 log and reporting provisions of 29 CFR 1910.502(q)(2)(ii), (q)(3)(ii)-(iv), and (r) in effect, as they were adopted under a separate provision of the OSH Act, section 8. MNOSHA proposes to permanently adopt certain provisions of the Healthcare ETS published in the Federal Register on June 21, 2021.

This rule proposal incorporates by reference paragraphs of the Healthcare ETS that include the recordkeeping requirements for a COVID-19 log. This requires covered employers with more than 10 employees to record COVID-19 cases of their employees on their COVID-19 log if a worker is infected by COVID-19, regardless of whether the instance is connected to exposure at work.

This rule adoption also requires covered employers to report to MNOSHA each work-related COVID-19 fatality within 8 hours of the employer learning about the fatality, and each work-related in-patient hospitalization within 24 hours of the employer learning about the hospitalization regardless of when the fatality or hospitalization occurred. As stated in 29 CFR 1910.502(r)(2), the employer must follow the requirements in 29 CFR 1904.39, except for 29 CFR 1904.39(a)(1) and (2) and (b)(6).

By this notice, Minnesota OSHA proposes to adopt the final rule published in the *Federal Register* June 21, 2021 for "Occupational Exposure to COVID-19; Emergency Temporary Standard," with the exception of 29 CFR 1910.502 (c) - (p), (s); 29 CFR 1910.504; 29 CFR 1910.505; and 29 CFR 1910.509.

5205.0010 ADOPTION OF FEDERAL OCCUPATIONAL SAFETY AND HEALTH STANDARDS BY REFERENCE.

[For text of subparts 1 and 1a, see Minnesota Rules]

Subp. 2. **Part 1910.** Part 1910: Occupational Safety and Health Standards as published in Volume 43, No. 206 of the Federal Register on October 24, 1978, and corrected in Volume 43, No. 216 on November 7, 1978, which incorporates changes, additions, deletions, and corrections made up to November 7, 1978; and subsequent changes as follows:

[For text of items A to SS, see Minnesota Rules]

TT. Federal Register, Volume 86, No. 116, pages 32376-32628, dated June 21, 2021: "Occupational Exposure to COVID-19; Emergency Temporary Standard," with the exception of 1910.502 (c) to (p) and (s), 1910.504, 1910.505, and 1910.509.

[For text of subparts 3 to 7, see Minnesota Rules]

Official Notices

Pursuant to *Minnesota Statutes* §§ 14.101, an agency must first solicit comments from the public on the subject matter of a possible rulemaking proposal under active consideration within the agency by publishing a notice in the *State Register* at least 60 days before publication of a notice to adopt or a notice of hearing, and within 60 days of the effective date of any new statutory grant of required rulemaking.

The *State Register* also publishes other official notices of state agencies and non-state agencies, including notices of meetings and matters of public interest.

Department of Administration

Notice of Vacancy for State Designer Selection Board for One Public Member representing ACEC but, does not need to be an ACEC member

The State of Minnesota, State Designer Selection Board has a public member vacancy, representing ACEC but, does not need to be an ACEC member. Application information is available on the Minnesota Secretary of State Open Commissions & Appointments website at ***https://www.sos.state.mn.us/boards-commissions/***. Applications are due by September 1, 2022.

The State Designer Selection Board (SDSB) selects the primary designer on building construction or remodeling projects as requested by state agencies, the University of Minnesota and Minnesota State Colleges and Universities (MN State) on all projects with an estimated construction cost greater than $2,000,000, and on planning projects with estimated fees greater than $200,000. The state Designer Selection Board consists of seven individuals, the majority of whom must be Minnesota residents. Each of the following four organizations shall nominate one individual whose name and qualifications shall be submitted to the commissioner of administration for consideration: the Consulting Engineers Council of Minnesota after consultation with other professional engineering societies in the state; the AIA Minnesota; the Minnesota chapter of the Associated General Contractors after consultation with other commercial contractor associations in the state; and the Minnesota Board of the Arts. The commissioner may appoint the four named individuals to the board but may reject a nominated individual and request another nomination. The fifth member shall be a representative of the user agency, the University of Minnesota, or the Minnesota State Colleges and Universities, designated by the user agency. The remaining two citizen members shall also be appointed by the commissioner.
The State is dedicated to building a culturally diverse board committed to selecting qualified designers that reflect Minnesota's diversity, and strongly encourages applications from women, minorities, individuals with disabilities and covered veterans. Due to Covid-19, Shortlisting and interview meetings are currently held on Tuesdays at 8:30 a.m. via WebEx Events. If a Shortlisting or Interview meeting is held in person, it will be at the Administration Building, 50 Sherburne Ave, St. Paul MN 55155, 116B. Notice of meetings is published at ***https://mn.gov/admin/government/construction-projects/sdsb/***.

The State of Minnesota reserves the right to extend or re-open the application process. Questions regarding the open appointments application process can be directed to 651-297-5845 or ***open.appointments@state.mn.us***.

Minnesota Department of Health

Notice of the List of Analytes Available for Accreditation

Related to Minnesota Statutes, 144.98, Governing Environmental Laboratory Accreditation

This notice is given to meet requirements in Minnesota Statutes 144.98, Subpart 3a (b).

Every six months, the Minnesota Department of Health reviews the list of analytes available for accreditation and publishes revisions to the list. The department revises the list based on recommendations from the state and federal agencies utilizing the environmental laboratory accreditation program. The department reviewed the list of analytes and added the following analytes, 2H,2H,3H,3H-Perfluorooctanoic acid (5:3FTCA, CAS#: 914637-49-3), 3-Perfluoroheptyl propanoic acid (7:3FTCA, CAS#: 812-70-4), 3-Perfluoropropyl propanoic acid (3:3FTCA, CAS#: 356-02-5), Lambda-cyhalothrin (CAS#: 91465-08-6), Clopyralid (CAS#: 1702-17-6), Fomesafen (CAS#: 72178-02-0), Mesotrione (CAS#: 104206-82-8), Tembotrione (CAS#: 335104-84-2), Flumetsulam (CAS#: 98967-40-9), Imazethapyr (CAS#: 81335-77-5), Sulfentrazone (CAS#: 122836-35-5), (Aminomethyl)phosphonic acid (AMPA, CAS#: 1066-51-9), Glufosinate (CAS#: 51276-47-2), 2,3,3,-Tetrafluoro-2-(heptafluoropropoxy)propanoate (Gen-X, CAS#: 62037-80-3), 8:2 Fluorotelomer alcohol (8:2 FTOH, CAS#: 678-39-7), 8:2 Fluorotelomer phosphate diester (8:2 diPAP, CAS#: 678-41-1), Perfluoro-4-ethylcyclohexanesulfonic acid (PFECHS, CAS#: 133201-07-7), 2-Perfluorooctyl ethanoic acid (8:2 FTCA, CAS#: 27854-31-5), 2H-Perfluoro-2-decenoic acid (8:2 FTUCA, CAS#: 70887-84-2), 2H-Perfluoro-2-octenoic acid (6:2 FTUCA, CAS#: 70887-88-6), 2-Perfluorohexyl ethanoic acid (6:2 FTCA, CAS#: 83826-12-3), and 2-Perfluorodecyl ethanoic acid (10:2 FTCA, CAS#: 53826-13-4) to the list previously published.

The list of analytes available for certification by the department will be posted on the program's website http://***www.health.state.mn.us/accreditation***. To submit comments on the list or request additional information, please contact Stephanie Drier, Minnesota Department of Health, Environmental Laboratory Accreditation Program, 625 Robert Street North, St. Paul, MN 55164-0502, phone (651) 201-5324, email ***stephanie.drier@state.mn.us***

Minnesota Pollution Control Agency (MPCA)

Environmental Analysis and Outcomes Division

Public Notice on State Implementation Plan Revision

NOTICE IS HEREBY GIVEN that the Commissioner of the Minnesota Pollution Control Agency (MPCA) has determined that a Regional Haze State Implementation Plan (SIP) update must be submitted to meet Minnesota's requirements under section 169A of the Clean Air Act (CAA). The draft SIP update is now available for public comment.

Background. Section 169A of the CAA requires that each state prepare and submit to the U.S. Environmental Protection Agency (EPA) SIPs to achieve national visibility goals in designated Class I areas. In Minnesota, Voyageurs National Park and the Boundary Waters Canoe Area Wilderness are subject to the Regional Haze Rule established in 40 CFR Part 51, Subpart P.

Purpose of the SIP revision. The purpose of this SIP revision is to fulfill Minnesota's responsibility under the CAA to work towards natural visibility conditions in Minnesota's Class I areas.

When states update the rules and statutes that are part of their SIP, they must submit those updates to EPA for review and approval into the SIP. Minnesota first submitted a Regional Haze SIP during the first implementation period in 2009. This SIP draft covers the second implementation period.

The MPCA will consider changing the contents of the proposed SIP revision based on comments received during the comment period. Following the end of the comment period, the Commissioner will decide whether to submit the proposed SIP revision to the EPA.

Submitting written comments

Comments may be submitted by: (1) Online at ***https://www.pca.state.mn.us/air/minnesotas-regional-haze-state-implementation-plan*** (2) By mail to: Maggie Wenger, Minnesota Pollution Control Agency, Environmental Analysis and Outcomes Division, 520 Lafayette Road North, St. Paul, Minnesota 55155-4194.

Availability of SIP. A copy of the proposed SIP revision is available on the MPCA's web site at ***http://www.pca.state.mn.us/public-notices***. A copy of the proposed SIP revision is also available upon request by contacting Maggie Wenger at 651-757-2007 or ***Maggie.wenger@state.mn.us***, or can be mailed to any interested person upon the MPCA's receipt of a written request. Additional materials relating to the SIP revision are available for inspection by appointment at the MPCA, 520 Lafayette Road North, St. Paul, Minnesota 55155-4194, between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday. To examine these materials, or for more information, please contact Maggie Wenger. All MPCA offices may be reached by calling 1-800-657-3864.

Public comment period and potential public meeting. The public comment period begins on August 22, 2022 and ends on October 7, 2022. Your comments must be in writing and received by October 7, 2022. Written comments may be submitted to them at the mailing address or web address listed above.

A public information meeting will be held to provide information, receive public input, and answer questions about the proposed SIP revision. The public meeting will be held on September 22, 2022 from 2:00-4:00 PM at the MPCA St. Paul office and via Microsoft Teams virtual meeting. Information on attending the meeting in person or virtually is available at ***http://www.pca.state.mn.us/public-notices.***

State Grants & Loans

In addition to requests by state agencies for technical/professional services (published in the State Contracts Section), the *State Register* also publishes notices about grants and loans available through any agency or branch of state government. Although some grant and loan programs specifically require printing in a statewide publication such as the State Register, there is no requirement for publication in the *State Register* itself. Agencies are encouraged to publish grant and loan notices, and to provide financial estimates as well as sufficient time for interested parties to respond.

SEE ALSO: Office of Grants Management (OGM) at: *http://www.grants.state.mn.us/public/*

Department of Employment and Economic Development (DEED)

Notice of Grant Opportunity

NOTICE IS HEREBY GIVEN that the Minnesota Department of Employment and Economic Development (DEED) places notice of any available grant opportunities online at ***https://mn.gov/deed/about/contracts/open-rfp.jsp***

Department of Human Services

Behavioral Health Division

Addendum to Request for Proposals for a Grantee to Develop and Implement Substance Use Disorder Primary Prevention to Reduce Youth Alcohol, Nicotine, and Other Drug Use In Black, Indigenous, and People of Color Communities

The Minnesota Department of Human Services through its Behavioral Health Division has published an Addendum to its Request for Proposal for a Grantee to develop and implement substance use disorder primary prevention to reduce youth alcohol, nicotine, and other drug use in black, indigenous, and people of color communities that was published in the July 25, 2022 State Register. In the Addendum, a correction is made to the original RFP whereas organizations who are receiving American Rescue Plan Act (ARPA) or Consolidated Appropriations Act (CAA) funds are eligible to respond to this RFP.

The text of the RFP Addendum can be viewed by visiting the Minnesota Department of Human Services RFP web site: ***https://mn.gov/dhs/partners-and-providers/grants-rfps/open-rfps/***.

For more information please contact: Aaron Garcia

Department of Human Services
Behavioral Health Division
Phone: (651) 766-4117
aaron.e.garcia@state.mn.us

This is the only person designated to answer questions by potential responders regarding this request.

To obtain this information in a different format, please email ***Emily.Waymire@state.mn.us***.

This request does not obligate the State to complete the work contemplated in this notice. The State reserves the right to cancel this solicitation. All expenses incurred in responding to this notice are solely the responsibility of the responder.

Department of Labor and Industry

Construction Codes and Licensing Division

Notice of Request for Proposals for the Building Official Training Grant Program

The Minnesota Department of Labor and Industry announces the availability of $390,000 in grant funding for the implementation and coordination of the Building Official Training Grant Program in the State of Minnesota. The performance period for five (5) full-time grants and two (2) half-time grants will be from the date the contract is executed to December 31, 2023, depending on which training grant is selected by the applicant.

I. Purpose

The purpose of the Building Official Training Grant Program (hereafter referred to as the BOT Grant Program) from the Minnesota Department of Labor and Industry (DLI) is to provide support through partial funding and training guidance, for the implementation and coordination of partnerships between the State of Minnesota and qualified municipalities, that will provide education, work experience and competency-based skills training that prepares trainees, 18 years of age and older, to achieve a building official-limited (BOL) certification and gain experience in building inspection and plan review while working toward their building official certification.

II. Objective of the RFP

DLI seeks proposals from qualified municipalities to partner with and provide partial funding through competitive grants.

The objective is to promote, encourage and provide support to municipalities who will educate and train individuals on their path to becoming building officials. The municipalities will provide training through educational instruction and paid on-the-job learning opportunities in the administration and enforcement of the Minnesota State Building Code. Successful grant applicants will demonstrate the ability to achieve these objectives.

III. Eligibility

Proposals will be accepted and funding will be allocated through a competitive process. The deadline to submit a grant proposal to the Minnesota Department of Labor and Industry is 4 p.m. September 9, 2022. The Grant Program committee will review and score grant applications and proposals

IV. Application Process

For information about this grant, eligibility, documents, proposal requirements and deadlines email your requests to: ***bot.dli@state.mn.us*** also the documents are available at ***www.dli.mn.gov/bot***.

State Contracts

Informal Solicitations: Informal solicitations for professional/technical (consultant) contracts valued at over $5,000 through $50,000, may either be published in the *State Register* or posted on the Department of Administration, Materials Management Division's (MMD) Web site. Interested vendors are encouraged to monitor the P/T Contract Section of the MMD Website at *www.mmd.admin.state.mn.us* for informal solicitation announcements.

Formal Solicitations: Department of Administration procedures require that formal solicitations (announcements for contracts with an estimated value over $50,000) for professional/technical contracts must be published in the *State Register.* Certain quasi-state agency and Minnesota State College and University institutions are exempt from these requirements.

Requirements: There are no statutes or rules requiring contracts to be advertised for any specific length of time, but the Materials Management Division strongly recommends meeting the following requirements: $0 - $5000 does not need to be advertised. Contact the Materials Management Division: (651) 296-2600 $5,000 - $25,000 should be advertised in the *State Register* for a period of at least seven calendar days; $25,000 - $50,000 should be advertised in the *State Register* for a period of at least 14 calendar days; and anything above $50,000 should be advertised in the *State Register* for a minimum of at least 21 calendar days.

Department of Administration

Notice of Availability of Request for Proposal (RFP) for Designer Selection for: New MnDOT Jordan Truck Station MnDOT Building Number 90953 (SDSB Project # 22-02)

The State of Minnesota, acting through Department of Transportation through the State Designer Selection Board, is soliciting proposals from interested, qualified consultants for architectural and engineering design services for the above referenced project.

A full Request for Proposals is available on the Minnesota Department of Administration's website at ***https://mn.gov/admin/government/construction-projects/sdsb/projects/*** (click SDSB Project #22-02).

A **mandatory** informational meeting is scheduled for **August 25th, 2022 at 11:00 CT on Microsoft TEAMS. This will include a review of the scope of work. Please email Wendy Kufner at *wendy.kufner@state.mn.us* by noon CT on August 24th, 2022 to receive an invitation.**

Any questions should be directed to Wendy Kufner at ***wendy.kufner@state.mn.us***. Project questions will be taken by this individual only. Questions regarding this RFP must be received by **Tuesday, August 30th, 2022 no later than 12:00 PM Central Time**.

Proposals must be delivered to ***SDSB.Proposals.ADM@state.mn.us*** not later than **Tuesday, September 6, 2022, by 12:00 noon CT.** Late responses will not be considered.

The Department of Transportation is not obligated to complete the proposed project and reserves the right to cancel the solicitation if it is considered to be in its best interest.

Minnesota State Colleges and Universities (Minnesota State)

Notice of Bid and Contracting Opportunities

Minnesota State is now placing additional public notices for contract opportunities, goods/commodities and related services on its Vendor and Supplier Opportunities website (***https://www.minnstate.edu/vendors/index.html***). New public notices may be added to the website on a daily basis and be available for the time period as indicated within the public notice.

If you have any questions regarding this notice or are having problems viewing the information on the Vendor and Supplier Opportunities website, please email the Minnesota State Procurement Unit at ***Sourcing@MinnState.edu***.

State Contracts

Department of Corrections

Request for Proposals for Community Services Providers to facilitate CBI-EMP – Employment Matters

PROJECT NAME: Employment Matters

DETAILS: ON Tuesday, August 8, 2022 the Minnesota Department of Corrections will be soliciting proposals from nongovernmental organizations to provide University of Cincinnati Corrections Institute's Cognitive-Behavioral Interventions for Employment – Adult (CBI-EMP). Cognitive-Behavioral Interventions for Employment (CBI-EMP) is designed for justice involved individuals who are moderate to high risk of re-offense with a specific need in the area of employment. The DOC is looking to contract with Community Service Providers (CSPs) to facilitate these pre and post release services. Pre-release services will feature a co-facilitated groups with a DOC staff and CSP staff. Post-release services will be provided by CSP only, as well as individualized one to one follow up to strengthen application of learned skills.

Funding for this contract is provided through a Federally awarded BJA Grant *Employment Matters*. Funding is available through September 2023. There is a possibility of an option to extend.

Work is anticipated to start on or after October 1, 2022.

COPY REQUEST: A copy of this request will be available at this link: ***https://mn.gov/doc/staff-partners/doing-business-doc/request-proposals/***. The event will also be available through SWIFT using the Supplier portal (***https://supplier.systems.state.mn.us/***).

PROPOSAL DEADLINE: Proposals in response to the Request for Proposals in this advertisement must be received via email or through SWIFT Supplier Portal not later than **4:00 pm, Central Time, Tuesday August 29, 2022. Late proposals will not be considered.** Fax or mailed proposals will not be considered.

This request does not obligate the State of Minnesota to award a contract or complete the proposed program, and the State reserves the right to cancel this solicitation if it is considered in its best interest. All costs incurred in responding to this solicitation will be borne by the responder.

Department of Military Affairs

Request for Proposals for Consultant Services for Mechanical Systems Replacement, Building 17-1, at Camp Ripley, Little Falls, Minnesota (Project No. 23112)

PROJECT NAME: Consultant Services for Mechanical Systems Replacement, Building 17-1, at Camp Ripley, Little Falls, Minnesota (Project No. 23112)

DETAILS: The State of Minnesota, Department of Military Affairs, is soliciting proposals from interested, qualified providers for Consultant Services for Mechanical Systems Replacement, Building 17-1, at Camp Ripley, Little Falls, Minnesota (Project No. 23112). The State is in need of architectural, mechanical, electrical, and structural engineering services to replace existing mechanical systems within the original structure of Building 17-1, located at Camp Ripley, Little Falls, MN. Work is anticipated to start January 2023.

COPY REQUEST: A full Request for Proposal (RFP) is available on the Minnesota National Guard's website: ***http://minnesotanationalguard.ng.mil/requests-for-proposal***

PROPOSAL DEADLINE: Proposals in response to the Request for Proposals in this advertisement must be received via email not later than **2:00 p.m., Central Time, September 7, 2022. Late proposals will not be considered.** Fax and mailed proposals will not be considered.

This request does not obligate the State of Minnesota to award a contract or complete the proposed program, and the State reserves the right to cancel this solicitation if it is considered in its best interest. All costs incurred in responding to this solicitation will be borne by the responder.

Department of Military Affairs

Request for Proposals for Consultant Services for Renovation of the Water Treatment Plant At Camp Ripley, Little Falls, Minnesota (Project No. 22111)

PROJECT NAME: Consultant Services for Renovation of the Water Treatment Plant At Camp Ripley, Little Falls, Minnesota (Project No. 22111)

DETAILS: The State of Minnesota, Department of Military Affairs, is soliciting proposals from interested, qualified providers for Consultant Services for Renovation of the Water Treatment Plant At Camp Ripley, Little Falls, Minnesota (Project No. 22111). Camp Ripley requires a design for the removal and replacement of the existing water treatment system. This involves the removal and replacement of the existing pressure filters and southern wall of the Water Treatment Plant. Work is anticipated to start November 2022.

COPY REQUEST: A full Request for Proposal (RFP) is available on the Minnesota National Guard's website: ***http://minnesotanationalguard.ng.mil/requests-for-proposal***

PROPOSAL DEADLINE: Proposals in response to the Request for Proposals in this advertisement must be received via email not later than **2:00 p.m., Central Time, September 7, 2022. Late proposals will not be considered.** Fax and mailed proposals will not be considered.

This request does not obligate the State of Minnesota to award a contract or complete the proposed program, and the State reserves the right to cancel this solicitation if it is considered in its best interest. All costs incurred in responding to this solicitation will be borne by the responder.

Office of the Revisor of Statutes

Notice of Request for Website Design and Development Contractor

NOTICE IS HEREBY GIVEN that the Office of the Revisor of Statutes intends to enter into a contract to provide web design and development services to modify and enhance the existing internal and external web-based systems. The initial contract is for a period of one year beginning approximately October 1, 2022, but the contract may be extended for up to 24 months. The work includes addressing long standing issues and improving the quality of the office's code base, including assisting with the migration away from legacy PHP pages and planning for moving to a containerized environment. Tasks may include:

- Convert PHP pages to JavaScript or Django
- Evaluate and improve environment handling of web code
- Evaluate and provide recommendations regarding web technology stack and frameworks (Python, PHP, Nginx), CI/CD, test plans, and warnings and errors of the current code base
- Investigate and assist with docker containerization

All responses must include a cover letter and resume, together with hourly rates and references. Responses must be received no later than 4:30 p.m. on Friday, September 16, 2022. The Revisor's Office reserves the right to award all, a part, or none of the above-described contract. Additional information on the services to be provided is available at ***https://www.revisor.mn.gov/employment/***

State Contracts

Minnesota Department of Transportation (MnDOT)

Engineering Services Division

Notices Regarding Professional/Technical (P/T) Contracting

P/T Contracting Opportunities: MnDOT is now placing additional public notices for P/T contract opportunities on the MnDOT's Consultant Services website. New public notices may be added to the website on a daily basis and be available for the time period as indicated within the public notice.

Taxpayers' Transportation Accountability Act (TTAA) Notices: MnDOT is posting notices as required by the TTAA on the MnDOT Consultant Services website.

MnDOT's Prequalification Program: MnDOT maintains a Pre-Qualification Program in order to streamline the process of contracting for highway related P/T services. Program information, application requirements, application forms and contact information can be found on MnDOT's Consultant Services website. Applications may be submitted at any time for this Program.

MnDOT Consultant Services website: ***www.dot.state.mn.us/consult***

If you have any questions regarding this notice, or are having problems viewing the information on the Consultant Services website, please all the Consultant Services Help Line at 651-366-4611, Monday – Friday, 9:00am – 4:00pm.

Non-State Public Bids, Contracts & Grants

The State Register also serves as a central marketplace for contracts let out on bid by the public sector. The *State Register* meets state and federal guidelines for statewide circulation of public notices. Any tax-supported institution or government jurisdiction may advertise contracts and requests for proposals from the private sector. It is recommended that contracts and RFPs include the following: 1) name of contact person; 2) institution name, address, and telephone number; 3) brief description of commodity, project or tasks; 4) cost estimate; and 5) final submission date of completed contract proposal. Allow at least three weeks from publication date (four weeks from the date article is submitted for publication). Surveys show that subscribers are interested in hearing about contracts for estimates as low as $1,000. Contact editor for further details.

Besides the following listing, readers are advised to check: *http://www.mmd.admin.state.mn.us/solicitations.htm* as well as the Office of Grants Management (OGM) at: *http://www.grants.state.mn.us/public/.*

City of Edina

Notice of Request for Qualifications (RFQ) Architectural and Engineering Services for Community Health and Safety Center

Project Name: Community Health and Safety Center

The City of Edina is issuing a Request for Qualifications (RFQ) August 1st, 2022 for an Architectural and Engineering firm to provide professional services for the new Community Health and Safety Center project. The selected firm will work with our Community Health and Safety Center Project Team which will be comprised of City Staff and stakeholders, and Owner's Representative, and a Construction Management firm to provide pre-schematic programming/planning, concept design, schematic design, design development, construction documents, and construction administration services for a new ground up facility at 4401 West 76th Street, Edina MN.

Availability Of Bidding Documents: Bidding Documents are on file for inspection at the QuestCDN website indicated. Bidders desiring bidding documents for personal use may secure a complete digital set at ***http://www.questcdn.com***. Bidders may download the complete set of digital bidding documents for $30 by entering eBidDoc™ **#8264017** in the "Search Projects" page. Contact Quest Construction Data Network at (952) 233-1632 or ***info@questcdn.com*** for assistance. Hard copy bidding documents will not be made available to Bidders.

Proposal Submissions Close At: 2:00 p.m, Thursday, August 25, 2022

Metropolitan Airports Commission (MAC)

Notice of call for Bids for 2022 Terminal 1 Miscellaneous Modifications

Airport Location: **Minneapolis-St. Paul International Airport**
Project Name: **2022 Terminal 1 Miscellaneous Modifications**
MAC Contract No.: **106-2-951**
Bids Close At: **2:00 PM on September 13, 2022**
Bid Opening Conference Call: 3:00 PM on September 13, 2022
Teleconference Dial In #: **1-612-405-6798**
Conference ID #: **681 090 675#**

Notice to Contractors: Electronic Bid Submission for the project listed above will be received by the MAC, a public corporation, via QuestCDN ***https://questcdn.com/*** until the official time and date as displayed in QuestCDN Online.

Note: You can sign up on our web site (***https://metroairports.org/doing-business/solicitations***) to receive email notifications of new business opportunities.

Targeted Group Businesses (TGB): The goal of the MAC for the utilization of Targeted Group Businesses on this project is 8%.

Bid Security: Each bid shall be accompanied by a "Bid Security" in the form of a certified check made payable to the MAC in the amount of not less than five percent (5%) of the total bid, or a surety bond in the same amount, running to the MAC, with the surety company thereon duly authorized to do business in the State of Minnesota.

Availability of Bidding Documents: Bidding documents are available at QuestCDN Online indicated below and at the Minnesota Builders Exchange; Rochester Builders Exchange; Dodge Data and Analytics; and NAMC-UM Plan Room. Bidders desiring bidding documents for personal use may secure a complete digital set at ***https://questcdn.com/***. Bidders may download the complete set of digital documents for $15.00, or other fee as determined by QuestCDN, by entering eBidDocTM #8272612 in the "Search Projects" page. Contact Quest Construction Data Network at (952) 233-1632 or ***info@questcdn.com*** for assistance. Hard copy bidding documents will not be made available to Bidders. Bid documents for this project may be viewed for no cost at QuestCDN Online. For this project, bids will **ONLY** be received electronically. Contractors submitting an electronic bid will be charged an additional $30.00, or other fee as determined by QuestCDN, at the time of bid submission via the online electronic bid service QuestCDN Online.

MAC Internet Access of Additional Information: A comprehensive Notice of Call for Bids for this project will be available on August 15, 2022, at MAC's web address of ***https://metroairports.org/doing-business/solicitations*** (construction bids).

Metropolitan Airports Commission (MAC)

Notice of Call for Bids for 2022 Plumbing Infrastructure Upgrade Program

Airport Location: **Minneapolis-St. Paul International Airport**
Project Name: **2022 Plumbing Infrastructure Upgrade Program**
MAC Contract No.: **106-2-949**
Bids Close At: **2:00 PM on September 13, 2022**
Bid Opening Conference Call: 3:00 PM on September 13, 2022
Teleconference Dial In #: **1-612-405-6798**
Conference ID #: **681 090 675#**

Notice to Contractors: Electronic Bid Submission for the project listed above will be received by the MAC, a public corporation, via QuestCDN ***https://questcdn.com/*** until the official time and date as displayed in QuestCDN Online.

Note: You can sign up on our web site (***https://metroairports.org/doing-business/solicitations***) to receive email notifications of new business opportunities.

Bid Security: Each bid shall be accompanied by a "Bid Security" in the form of a certified check made payable to the MAC in the amount of not less than five percent (5%) of the total bid, or a surety bond in the same amount, running to the MAC, with the surety company thereon duly authorized to do business in the State of Minnesota.

Availability of Bidding Documents: Bidding documents are on file for inspection at the QuestCDN Online indicated below and at the Minnesota Builders Exchange; Rochester Builders Exchange; Dodge Data and Analytics; and NAMC-UM Plan Room. Bidders desiring bidding documents for personal use may secure a complete digital set at ***https://www.questcdn.com***. Bidders may download the complete set of digital documents for $15.00, or other fee as determined by QuestCDN, by entering eBidDocTM #8277973 in the “Search Projects” page. Contact Quest Construction Data Network at (952) 233-1632 or ***info@questcdn.com*** for assistance. **Hard copy bidding documents will not be made available to Bidders**. Bid documents for this project may be viewed for no cost at QuestCDN Online. For this project, bids will **ONLY** be received electronically. Contractors submitting an electronic bid will be charged an additional $30.00, or other fee as determined by QuestCDN, at the time of bid submission via the online electronic bid service QuestCDN Online.

MAC Internet Access of Additional Information: A comprehensive Notice of Call for Bids for this project will be available on August 22, 2022, at MAC’s web address of ***https://metroairports.org/doing-business/solicitations*** (construction bids).

Metropolitan Airports Commission (MAC)

Request for Statements of Qualifications for Employment Related Legal Services

The Metropolitan Airports Commission (“MAC”) is requesting Statements of Qualifications (SOQ) from law firms interested in assisting MAC with Employment Related Legal Services.

MAC’s Request for Qualifications for Employment Related Legal Services is available on the following website at: ***https://metroairports.org/doing-business/solicitations***.

You may also contact Wendy Jo Cornelius, Manager, Legal Administration, at ***wendy.cornelius@mspmac.org*** with any questions by or before Friday, September 2, 2022.

The SOQs are due on or before 4:00 p.m. on Friday, September 16, 2022.

Midwestern Higher Education Compact (MHEC)

Request for Proposals for Data Analytics for Student Success, Institutional Efficiencies, and Integration MHEC-RFP-08152022

PROJECT NAME: Data Analytics for Student Success, Institutional Efficiencies, and Integration MHEC-RFP-08152022

DETAILS: The Midwestern Higher Education Compact (MHEC) is competitively soliciting proposals on behalf of MHEC's 12 Compact member states for innovative and cost-effective Data Analytics for Student Success, Institutional Efficiencies, and Integration. The Midwestern Higher Education Compact (MHEC) is an instrumentality of 12 Midwestern states (Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin). The Compact was established in 1991 through a common statute enacted into law by each of the member states (Minnesota Statute – Section 135A.20). MHEC's mission is to bring together midwestern states to develop and support best practices, collaborative efforts, and cost-sharing opportunities. Through these efforts it works to ensure strong, equitable postsecondary educational opportunities and outcomes for all.

MHEC has determined that developing a region-wide acquisition strategy for higher education Data Analytics for Student Success, Institutional Efficiencies, and Integration through one or more providers will benefit both the higher education community and the provider(s). MHEC is seeking competitive solicitations with the intent to negotiate master agreement terms and conditions, licensing, and pricing. The resulting master agreement will allow an institution to focus most of its energy on finding the technology solution that best fits its needs instead of the contract itself. The result of a master agreement facilitates a direct relationship between the technology provider(s) and institution(s) and contains discounted pricing as well as terms and conditions that are better than most higher education institutions can negotiate individually.

For further information about the Compact's education technology contracts, visit ***https://www.mhec.org/contracts/technology***

PUBLISH DATE: A comprehensive Request for Proposal (RFP) for Data Analytics for Student Success, Institutional Efficiencies, and Integration MHEC-RFP-08152022 will be available on August 15, 2022, at MHEC's website ***https://www.mhec.org/news***

COPY REQUEST: For a complete copy of the RFP, required submission materials or inquiries, visit website ***https://www.mhec.org/news*** or search RFP: Data Analytics for Student Success, Institutional Efficiencies, and Integration MHEC-RFP-08152022 or by email to:

Mr. Nathan Sorensen
Director of Government Contracts
Midwestern Higher Education Compact
105 Fifth Avenue South, Suite 450
Minneapolis, MN 55401
Phone: (612) 677-2767
E-mail: ***nathans@mhec.org***

PROPOSAL DEADLINE: All responses to this RFP must be received no later than Monday, September 12, 2022, 10 A.M. CT.

This Request for Proposal (RFP) does not obligate the Midwestern Higher Education Compact (MHEC) or its member states to award a contract and reserves the right to cancel this RFP if it is considered to be in its best interest.

Public Hearing Testimony on Minnesota Draft Regional Haze State Implementation Plan for the Second Implementation Period
Christine Goepfert, National Parks Conservation Association
September 22, 2022

Good afternoon, my name is Christine Goepfert and I am the Midwest Campaign Director at National Parks Conservation Association (NPCA). I am based in the Twin Cities where we've had a field office for more than a decade. Thank you for the opportunity to comment today on Minnesota's Draft Regional Haze State Implementation Plan for the Second Implementation Period.

NPCA is the oldest and largest nonpartisan, nonprofit advocacy organization for our national parks. We have over 1.7 million members and supporters across the country with over 31,000 here in Minnesota.

Minnesota has two Class 1 areas:

- Voyageurs National Park, which hosts more than 243,000 visitors a year and supports over $21 million in visitor spending in Minnesota; and
- Boundary Waters Canoe Area Wilderness, which saw over 166,000 visitors in 2021 per the U.S. Forest Service.

Over the decades, haze from cars and trucks, taconite facilities, coal-fired power plants and other industrial sources has degraded visibility and dirtied our air, harming people's health in our national parks and local communities. Today, air pollution remains one of the most serious threats facing national parks and driving climate change.

NPCA commends the Minnesota Pollution Control Agency (MPCA) for proposing a technically sound regional haze plan for this planning period. MPCA had a robust source selection process, a strong commitment to working with the National Park Service and other federal land managers throughout the consultation process, rejected international endpoint adjustments, and used a good initial screening cost threshold.

However, there are still things that MPCA could improve upon to ensure the strongest regional haze State Implementation Plan (SIP) is submitted to the EPA for approval.

MPCA selected but failed to require four-factor analyses from taconite facilities. MPCA should evaluate and require pollution control improvements at all the taconite facilities they initially selected.

These facilities emit more than 70% of the total haze emissions from Minnesota and not only impact Voyageurs and the Boundary Waters, but also national parks in neighboring states like Isle Royale, Wind Cave, Theodore Roosevelt and Badlands.

Moreover, the taconite facilities are located close to Hibbing, Chisholm, Virginia and Mount Iron, among other communities. These communities are negatively impacted by pollution from the mining processes at the taconite facilities. MPCA must consider environmental justice factors, which substantiate the need for sharp reductions in the state's haze plan.

Finally, NPCA urges MPCA to require cost-effective controls for the sugar beet processing and paper manufacturing facilities for which the costs were overestimated in the draft SIP. The National Park Service also recommended this, and we wholly support this action.

The Clean Air Act's Regional Haze Rule is an effective program that has resulted in real, measurable, and noticeable improvements in national park visibility and air quality. State Implementation Plans developed under the Regional Haze Rule are an opportunity—and obligation—for states including Minnesota to reduce pollution in their borders to help restore clean and clear skies at protected national parks and wilderness areas, and in our communities.

Thank you for your time today. NPCA will be submitting more detailed technical comments and we forward to reviewing improvements to this plan.

United States Department of the Interior

NATIONAL PARK SERVICE
601 Riverfront Drive
Omaha, NE 68102

1.A.2 (MWR-NRSS)

October 3, 2022

Mr. Hassan Bouchareb
Minnesota Pollution Control Agency
c/o Maggie Wenger
520 Lafayette Road
St. Paul, Minnesota 55155
Via MPCA Web Site Comment Form

Re: Comments on Minnesota's proposed Regional Haze State Implementation Plan for the Second Implementation Period

Dear Mr. Bouchareb:

Thank you for the opportunity to provide comments on the proposed Minnesota Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018–2028). National Park Service (NPS) staff consulted with the Minnesota Pollution Control Agency (MPCA) regarding SIP development on June 30, 2022 and provided written comments by email on July 11, 2022. We appreciate your consideration of our feedback and responses to our suggestions. We note that the public notice announcing the availability of the draft SIP did not include a summary of the conclusions and recommendations of the Federal Land Managers as required by statute (42 U.S.C. §7491).

Overall, the Minnesota draft regional haze SIP is one of the most technically sound and complete plans that the NPS has reviewed in this planning period. However, in some cases, NPS disagrees with the conclusions reached by MPCA. We continue to encourage Minnesota to seriously evaluate additional emission controls for the state's taconite facilities. Minnesota taconite facilities emit over 35,000 tons annually of visibility-impairing emissions and are relatively close to Voyageurs and Isle Royale National Parks. Based on an analysis of emissions relative to distance to NPS Class I areas, Minnesota ranked 9th in visibility impairing emissions within the U.S., with the taconite facilities comprising more than half of those impacts. As our analysis in the attached technical document demonstrates, there are more effective controls available that may be technically feasible and cost-effective.

In addition, the NPS finds that emission controls may be cost effective for American Crystal Sugar (ACS) Crookston, ACS East Grand Forks, Southern Minnesota Beet Sugar Cooperative, and for Power Boiler 9 at the Sappi Cloquet paper mill. Based on the public comment version of MPCA's SIP, we have revised some of our technical analyses, as reflected in the attachments to this letter. Specifically, the NPS has adjusted cost estimates based on the parameters used by MPCA in the latest draft of the SIP. Our revised analyses indicate that additional controls may be available at these facilities within the $7,600/ton cost threshold established by MPCA. The NPS recommends that cost-effective emission controls that achieve the greatest level of reductions be required for these facilities. We also continue to encourage Minnesota to evaluate additional controls for Boise White Paper.

The NPS manages 48 of the 156 mandatory Class I areas across the country where visibility is an important attribute. Minnesota contains one NPS-managed Class I area, Voyageurs National Park, and emissions from sources in the state can also affect visibility at nearby Isle Royale National Park in Michigan. We encourage Minnesota to take advantage of the opportunity this SIP provides to obtain further emission reductions. Applying the reasonable controls available to MPCA would make a difference for clear views in these parks and across the region.

We appreciate the opportunity to comment and look forward to continuing to work with Minnesota to improve and protect air quality and visibility in these Class I areas. If you have questions, don't hesitate to contact me or David Pohlman, Regional Air Resources Coordinator at 651-491-3497, david_pohlman@nps.gov.

Sincerely,

Herbert C. Frost, Ph.D., Regional Director,
National Park Service, Interior Region 3, 4, 5.

Attachments:
NPS-MN-RH-Tech-Comms.docx
NPS-MN-RH-Workbooks.zip

cc:
Nancy Finley, Associate Regional Director, Interior Regions 3, 4, 5
David Pohlman, Air Resources Specialist, Interior Regions 3, 4, 5
Bob DeGross, Superintendent, Voyageurs National Park
Denice Swanke, Superintendent, Isle Royale National Park
Melanie Peters, Regional Haze Lead, NPS Air Resources Division
Kirsten King, Lead, NPS Air Resources Division

Updated National Park Service (NPS) Regional Haze SIP feedback for the Minnesota Pollution Control Agency

October 3, 2022

Contents

1 Executive Summary

This document is an updated version of the consultation feedback provided by NPS in July, 2022.

The NPS commends the Minnesota Pollution Control Agency (MPCA) for a robust source selection process, commitment to working with NPS and other FLMs throughout the consultation process, rejection of international endpoint adjustments, and the use of a $10k initial screening cost threshold for controls. Overall, the Minnesota draft regional haze SIP is one of the most technically sound and complete plans that the NPS has reviewed in this planning period. However, in some cases NPS disagrees with the conclusions reached by MPCA. We continue to encourage Minnesota to seriously evaluate additional emission controls for the state's taconite facilities. Minnesota taconite facilities emit over 35,000 tons annually of visibility-impairing emissions and are relatively close to Voyageurs and Isle Royale National Parks. Based on an analysis of emissions relative to distance to NPS Class I areas, Minnesota ranked 9th in the US, with the taconite facilities comprising more than half of those impacts. As our analysis demonstrates, there are more effective controls available that may be technically feasible and cost-effective.

In addition, the NPS finds that emission controls for specific units may be cost effective for American Crystal Sugar (ACS) Crookston, ACS East Grand Forks, the Southern Minnesota Beet Sugar Cooperative, the Sappi Cloquet paper mill, and Boise White Paper. Based on the public comment version of MPCA's SIP, we have revised some of our technical analyses, as reflected in the attached workbooks and sections 3, 4, and 5 in this technical feedback document. Specifically, the NPS has adjusted cost estimates based on the parameters used by MPCA in the latest draft of the SIP. Revised analyses indicate that additional controls may be available at these facilities within the $7,600/ton cost threshold established by MPCA. The NPS recommends that cost-effective emission controls that achieve the greatest level of reductions be required for these facilities.

Emission reductions achieved through the regional haze planning process will advance the incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

2 Overarching Feedback

In response to the public review draft of the Minnesota Regional Haze SIP, the NPS has adjusted some previous feedback to reflect significant differences involving control cost estimates. Since 2019, the Chemical Engineering Plant Cost Index (CEPCI) has risen from 607.5 to 708.0 and the prime interest rate has risen from 3.25% to 5.5%. Instead of continuing to use these recent values in cost estimates, the NPS is revising the estimates previously provided to be consistent with the values used by MPCA—namely CEPCI of 607.5 and a 3.5% interest rate reflective of 2019 values. Following is a discussion of some overarching issues as well as how the revised NPS control cost estimates differ from those presented by MPCA.

2.1 Four-factor Analysis Screening - Demonstration of Effective Controls

In its July 2021 clarification memo, EPA advised that once a source is selected states must show why additional emission reductions are not necessary to make reasonable progress to use "effective controls" as rationale to forgo a four-factor analysis. Section 2.3 addressed the analytical expectations for "effectively controlled" determinations:

> *The underlying rationale for the "effective controls" flexibility is that if a source's emissions are already well controlled, it is unlikely that further cost-effective reductions are available.* ***A state relying on an "effective control" to avoid performing a four-factor analysis for a source should demonstrate why, for that source specifically, a four-factor analysis would not result in new controls and would, therefore, be a futile exercise.***

NPS finds that, for many of the sources that MPCA determined were effectively controlled, a 4-factor analysis may, in fact, have resulted in additional controls. See the comments on individual facilities for specific information.

2.2 Retrofit Factors in Cost Analyses

MPCA assumed a retrofit factor of 1.5 for adding SNCR to each of the coal-fired boilers at the beet sugar plants. Instructions for the SNCR cost estimation workbook advise:

> *If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.*

Neither the facilities nor MPCA provided adequate documentation to justify application of the maximum retrofit factor to a relatively simple technology like SNCR. As a result NPS analyses applied a retrofit factor of 1.0.

MPCA assumed a retrofit factor of 1.5 for adding SCR to each of the coal-fired boilers at the beet sugar plants. Instructions for the SCR cost estimation workbook advise:

> *If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.*

Most of the facilities and MPCA provided inadequate documentation to justify application of the maximum retrofit factor. NPS analyses used a retrofit factor of 1.0 except for the boiler at Southern Minnesota Beet Sugar which did provide justification for the 1.5 factor.

The MPCA retrofit factor of 1.33 for adding SCR to the biomass-fired boiler at the Sappi Cloquet paper mill represents a 66% increase versus a "greenfield" estimate. Due to a lack of documentation for the higher retrofit factor, NPS analyses applied the default 1.0 retrofit factor.

For taconite furnaces, NPS analyses applied a 1.5 retrofit factor due to the unproven nature of this control strategy on these emission units. UTAC used a retrofit factor of 1.6.

MPCA applied a 1.5 retrofit factor to SO_2 controls at Southern Minnesota Beet Sugar. MPCA also used undefined and undocumented retrofit factors provided by American Crystal Sugar for SO_2 controls at its Crookston and East Grand Forks facilities.

2.3 Control Efficiency and Outlet Emissions

NPS analyses applied Figure 1.1c of the SNCR section EPA's Control Cost Manual (CCM) to estimate control efficiency. If urea was proposed as the reagent, the NPS also applied Equation 1.17 to estimate the Normalized Stoichiometric Ratio.

For SCR, the CCM advises:

> *In practice, 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 NOx controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)*

To be conservative, NPS analyses assumed that addition of SCR to the coal- and biomass-fired boilers could reduce NO_x emissions no lower than 0.05 lb/mmBtu at not more than 90% control efficiency. For taconite furnaces, NPS analyses limited SCR control efficiency to 80% due to the unproven nature of this control strategy on these emission units.

MPCA assumed that addition of Dry Sorbent Injection (DSI) would require use of trona and a baghouse, and underestimated the control efficiency of using milled trona followed by a baghouse at 70%. According to Sargent & Lundy, the developer of the IPM DSI cost model:

> *Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO2. A baghouse used with sodium-based sorbents generally achieves a higher SO2 removal efficiency (70–90%) than that of an ESP.*

Also, NPS review of EPA's Clean Air Markets Data (CAMD) indicate that DSI can achieve 0.10 lb/mmbtu when followed by an ESP and 0.08 lb/mmBtu when followed by a baghouse .

2.4 Control Equipment Life

The CCM recommends a 20-year life for SNCR and 20–25 years for SCR on industrial boilers.

Because the coal-fired boilers at the beet sugar facilities operate on a seasonal basis with substantial downtime for maintenance, NPS analyses generally assumed a 25-year lifespan. MPCA assumed 20-year lives for SCR on all of these boilers.

For boilers at paper mills, MPCA used a 25-year life for SCR on the woodwaste-fired Sappi Cloquet Boiler #9 and 20 years for SCR on the natural gas-fired Boiler #1 at Boise White.

SCR on a natural-gas fired boiler is expected to last at least 25 years.

For taconite furnaces, NPS analyses assumed a 20-year SCR life due to the unproven nature of this control strategy on these emission units.

The CCM recommends a 30-year life for SO2 scrubbers. MPCA used 20 years for DSI at the beet sugar facilities.

2.5 Unsupported Costs

In at least one instance, MPCA relied on vendor quotes that were unavailable to NPS.

MPCA included costs that were unjustified (e.g., demolitions, ESP replacements, and stack replacements) and did not account for avoided operating costs (e.g., ESP removal).

2.6 Missing and Incomplete Analyses/Unsupported Control Determinations

Although MPCA did not discuss Selective Catalytic Reduction (SCR) at American Crystal Sugar's Crookston and East Grand Forks plants in its final draft, it included evaluations of SCR on all five boilers in Appendix E.

In its "Table 51. NO_x control information (MPCA revision)," MPCA estimated that addition of SCR at Southern Minnesota Beet Sugar could reduce NO_x emissions by 832 tons/yr at $5,986/ton. Even though the MPCA estimated cost-effectiveness is below its $7,600/ton threshold, it did not select this control strategy and provides no explanation for that decision.

MPCA provided an analysis of SNCR on Boise White Boiler #1 and determined that SNCR could reduce NOx emissions by 38 tons/yr at an annual cost of about $250,000 for a cost-effectiveness value of just over $6,600/ton of NO_x removed. Even though the MPCA estimated cost-effectiveness is well below its $7,600/ton threshold, it did not select this control strategy and provides no explanation for that decision.

2.7 Cost Effectiveness Thresholds

MPCA has relied on three sources of information in developing its cost-effectiveness threshold of $7,600/ton. The cost effectiveness from:

- the first implementation period
- other states' Regional Haze SIPs
- EPA's RACT/BACT/LAER clearing house

With respect to the first implementation period MPCA says that:

> *The Arkansas DEQ complied the costs of control determinations for BART and reasonable progress in the first planning period and scaled the cost per ton values in each determination to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI)…This analysis found that the cost-effectiveness of controls installed as a result of the first regional haze implementation period were generally $5,200 per ton of pollutant reduced.*

However, the Arkansas DEQ analysis is not applicable to this round of Reasonable Progress (RP) determinations because most of the data considered originates from BART analyses which included an additional fifth “degree of visibility improvement” factor. As such, cost-effectiveness was not necessarily the determining factor for BART determinations. Furthermore, BART cost-effectiveness values do not reflect the actual cost-effectiveness threshold or what the actual ceiling on an acceptable cost-effectiveness value might be. For example, a control measure that costs $1,000/ton may have been selected even though the actual cost-effectiveness threshold was much higher. Finally, EPA cautioned against using Round 1 BART thresholds in its comments to Arizona:

> *Given the differences between the BART factors and RP factors and the nature of the applicability criteria that would trigger BART and RP analyses, we do not necessarily consider the cost- effectiveness and visibility benefit values from BART determinations to be directly comparable to RP analyses.*[1]

With respect to cost thresholds from other states’ round two Regional Haze SIPs. Minnesota did not choose a single state as a guide but did consider its cost effectiveness threshold of $7,600/ton to be within the range of other state proposals.

The NPS is currently aware of the following cost-effectiveness thresholds that have been made public:

- AR: $5,200/ton
- AZ: $4,000 - $6,500/ton
- TX: $5,000/ton
- HI: $5,800/ton
- ID: $6,100/ton
- MN: $7,600/ton
- CO, NV, OR: $10,000/ton

[1] ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 52, [EPA–R09–OAR–2013–0588; FRL–9912–97–OAR], Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, ACTION: Final rule. September 3, 2014

With respect to EPA's RACT/BACT/LAER clearing house; MPCA found cost data for 11 coal-fired boilers (greater than 250 MMBtu/hr) that ranged from $158 to $9,242 per ton of pollutant reduced (NO_x or SO_2).

It is not clear if MPCA adjusted these costs for inflation. Nevertheless, the upper end of the range cited by MPCA is consistent with the cost-effectiveness thresholds selected by CO, NV, and OR.

It is also not clear if MPCA made control determinations based upon a derived cost-effectiveness threshold ($7,600/ton in 2019$) or if the $7,600/ton threshold was the result of a subjective determination of what constitutes a reasonable control strategy. If MPCA is basing its determinations on the $7,600/ton threshold, it should show how that value was derived. Otherwise, MPCA should provide a clearer explanation of how it arrived at it $7,600/ton threshold.

3 Electric Generating Facilities – Four-Factor Feedback

3.1 Hibbing Public Utilities Commission

In the FLM review draft SIP regarding the Hibbing Public Utilities Commission, the NPS agreed with MPCA's original determination that SNCR would be cost effective on the facility's three boilers. In the public draft SIP, MPCA determined that instead of requiring SNCR on the boilers it would establish new, lower NO_x emissions limits that would provide reductions equivalent to installing controls. The determination that these reductions will be equivalent to requiring SNCR is based upon a 40% reduction from the baseline NO_x emissions assumed in the four-factor analysis. Due to the uncertainty inherent in this assumption, the NPS continues to recommend that MPCA require installation of SNCR for NO_x reduction.

3.2 Minnesota Power–Boswell Energy Center

NPS comments on the FLM review draft SIP regarding the Boswell Energy Center noted that actual SO_2 emissions rates at Units 3 and 4 from 2015 through 2021 varied from 0.01 to 0.045 lb/MMBtu. These rates are much lower than the allowable rate of 0.2 lb SO_2/MMBtu. The NPS recommended that MPCA establish lower SO_2 emissions limits closer to the units' actual emissions rates to prevent backsliding. In their response to comments, the MPCA responded: "MPCA has no reason to believe that emission rates for these emission units will increase in the future given the existing enforceable requirements shown in Table 32." However, in reviews of emissions data from electrical generating facilities around the U.S. NPS has identified other electrical generating facilities with SO_2 controls that have experienced increases in emissions rates over time. The NPS continues to recommend that MPCA establish lower SO_2 emissions limits to ensure emissions rates remain low.

4 Sugar beet Processing Facilities – Four-Factor Feedback

MPCA conducted four-factor analyses for three beet sugar processing plants with the emissions shown below.

Table 1. MPCA Table 28. Q/d Analysis Emissions Data (tons/yr)

MPCA Table 28. Q/d Analysis emissions data (tons/yr)	NO_x	SO_2
American Crystal Sugar - Crookston	712.3	875.74
Southern Minnesota Beet Sugar Coop	1,053.38	831.99
American Crystal Sugar - East Grand Forks	680.63	1,005.68
Totals	2,446.31	2,713.41

MPCA is not requiring any emission reductions from these facilities. However, NPS estimates that emissions of over 1,700 ton/yr of SO_2 and 2,000 ton/yr of NOx could be eliminated by application of cost-effective emission controls.

4.1 American Crystal Sugar – Crookston[2]

4.1.1 Summary of NPS Recommendations for American Crystal Sugar–Crookston

NPS review of the four-factor analysis conducted for American Crystal Sugar – Crookston facility (ACSC--CRK) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Boilers 1, 2, and 3. In fact, NPS analyses show that the cost of control is more economical than estimated by MPCA when analyses are adjusted in accordance with the EPA Control Cost Manual (CCM).

The addition of Dry Sorbent Injection (DSI) with milled trona and replacement of the existing Electrostatic Precipitators (ESPs) with fabric filtration on all three boilers could reduce SO_2 emissions from this facility by about 600 tons/year for less than $5,000/ton. If the ESPs are retained (which MPCA did not evaluate), about 300 tons of SO_2 could be removed annually at $6,000/ton. The cost-effectiveness of both of these DSI options is less than half the MPCA estimates and well below the MPCA $7,600/ton cost-effectiveness threshold.

Although MPCA did not discuss Selective Catalytic Reduction (SCR) in its final draft, in its Appendix E it included evaluations of SCR on all three boilers. However, MPCA applied a 1.5 retrofit factor with none of the required documentation. MPCA also assumed a minimal 20-year SCR life and underestimated SCR control efficiency at 79%–81%. As a result, MPCA estimated

[2] MPCA's response to NPS feedback:
MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.

SCR's cost-effectiveness at over $12,000/ton for all three boilers. Instead, NPS estimates that, based upon CCM guidance, SCR could reduce NO_x emissions from this facility by over 300 tons/year for $7.400–$7,600/ton, which is at or below MPCA's acceptance threshold and well below the $10,000/ton threshold set by CO, NV, and OR.

The NPS recommends that MPCA require the addition of DSI with milled trona and a new baghouse as well as SCR on Boilers 1, 2, and 3 at American Crystal Sugar – Crookston. By requiring implementation of identified controls, MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.1.2 Facility Characteristics

ACSC--CRK operates three Babcock and Wilcox coal-fired stoker boilers equipped with modern over-fire air (OFA) control systems. The boilers are also equipped with high-efficiency ESPs to control particulate matter emissions. The maximum rated heat input of two identical boilers is 137 million British thermal units per hour (MMBtu/hr) each. The maximum rated heat input of the third boiler is 165 MMBtu/hr. All three boilers combust low sulfur subbituminous coal from the Powder River Basin. ACSC--CRK is located about 270 km southwest of Voyageurs National Park, a Class I area administered by the NPS. The 2017 National Emissions Inventory (NEI) shows plantwide emissions of 740 tons of NO_x and 775 tons of SO_2.

4.1.3 SO_2 Four-factor Analysis

Control Selection & Efficiency

The NPS supports ACSC's selection of Dry Sorbent Injection (DSI), Spray Dry Absorption (SDA) or a Circulating Dry Scrubber (CDS) in the category Dry FGD, and Wet Flue Gas Desulfurization (Wet FGD) for evaluation. (MPCA did not include Wet FGD.)

Control Selection & Efficiency

In the initial (2021) four-factor analysis submittal for ACSC—CRK, the consulting firm HDR showed that the cost-effectiveness of DSI to reduce SO_2 emissions was below $5,000/ton. This is quite cost-effective in spite of several factors that lead to overestimation of costs in the initial analysis. However, on February 1, 2022, HDR submitted an "Updated Dry Sorbent Injection Costs for American Crystal Sugar Company Four Factor Analysis" to MPCA revising those findings. HDR expressed concern that the ESPs at ACSC--CRK, which have historically provided around 99.1% control of PM, might not be able to handle the additional loading presented by DSI and still maintain compliance with mercury and PM limits. According to HDR:

> *Therefore, the FFA was updated to enhance the PM control by adding a fabric filter baghouse. The addition of a baghouse will allow higher sorbent injection rates while maintaining compliance with the applicable PM emission limits. Further, the additional system residence time, higher sorbent injection rates, and associated sorbent filter cake in the baghouse, will allow an increased control efficiency of 70% for SO_2.*

HDR provided little evidence to support its speculation that addition of DSI followed by the existing ESPs would result in non-compliance with particulate or mercury emission limits. On the contrary, NPS review finds substantial evidence to refute the HDR finding that DSI cannot be added without replacing the ESPs with baghouses. The S&L DSI documentation states, *"Trona,* *when captured in an ESP, typically removes 40 to 50% of* SO_2 *without an increase in particulate emissions…"*[3] The IPM DSI models include both ESPs and baghouses. The S&L DSI IPM model assumes that DSI with milled trona, for example, can achieve 70% removal when followed by an electrostatic precipitator (ESP) and 90% when followed by a baghouse (BGH). Also, NPS review of EPA's Clean Air Markets Data (CAMD) indicate that DSI can achieve 0.10 lb/mmbtu when followed by an ESP[4] and 0.08 lb/mmBtu when followed by a baghouse[5]. Furthermore, CAMD data for 2021 includes several coal-fired Electric Generating Units (EGUs) with DSI and ESPs.

Table 2. Examples of coal-fired Electric Generating Units (EGUs) with DSI, CAMD 2021

State	Facility Name	Unit ID	SO_2 (tons)	Calculated Avg. SO_2 Rate (lb/MMBtu)	Heat Input (MMBtu)	Unit Type	PM Control(s)
MN	Boswell	4	391	0.025	31,545,340	Tangentially-fired	Baghouse
MI	J H Campbell	1	2,758	0.275	20,090,010	Tangentially-fired	Baghouse
MI	J H Campbell	2	2,094	0.300	13,961,840	Cell burner boiler	Baghouse
IN	R Gallagher	2	49	0.631	154,982	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
IN	R Gallagher	4	68	0.720	189,738	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
WI	J P Madgett	B1	849	0.083	20,454,088	Dry bottom turbo-fired	Baghouse | ESP
OK	Northeastern	3313	4,564	0.340	26,816,608	Tangentially-fired	Baghouse | ESP
IL	Kincaid	2	1,083	0.093	23,285,397	Cyclone boiler	Electrostatic Precipitator
IL	Kincaid	1	808	0.093	17,366,842	Cyclone boiler	Electrostatic Precipitator
IL	Waukegan	7	501	0.095	10,522,238	Tangentially-fired	Electrostatic Precipitator
IL	Powerton	62	278	0.109	5,084,619	Cyclone boiler	Electrostatic Precipitator
IL	Powerton	61	304	0.111	5,502,464	Cyclone boiler	Electrostatic Precipitator
LA	Big Cajun 2	2B1	1,203	0.342	7,032,558	Dry bottom wall-fired	Electrostatic Precipitator
OR	Boardman	1SG				Dry bottom wall-fired	Electrostatic Precipitator

[3] **S&L:** Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO2. A baghouse used with sodium-based sorbents generally achieves a higher SO2 removal efficiency (70 to 90%) than that of an ESP. DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO2/MMBtu.

[4] See the Kincaid and Waukegan entries in Table 10 below.
[5] See the Madgett entry in Table 10 below.

Statutory Factor 1: Cost of Compliance

In its 2022 submittal, HDR states:

> *American Crystal Sugar Company (ACSCC) obtained site-specific vendor quotes for Dry Sorbent Injection (DSI) equipment in order to verify estimated capital equipment and annual operating costs included in the original Four Factor Analysis (FFA) for the ACSCC East Grand Forks (EGF) and Crookston (CRK) facilities.*

However, it did not provide the vendor information supporting its costs for DSI (and a new baghouse) and NPS cannot evaluate the use of that information.

In the revised analysis, HDR's cost-effectiveness of DSI increased to above $10,000/ton. Many of the costs in ACSC's Tables 4 & 5 and HDR's Table 2 are overestimated and NPS review of the HDR submittal identifies these issues:

- ACSC used a 20-year life for DSI; the CCM recommends 30 years for SO_2 scrubbers.
- ACSC's four-factor analyses assume that DSI with milled trona and a baghouse can achieve 70% control versus 90% control in the S&L IPM model.
- HDR proposes to "Extend three stacks to 200 ft." It is unclear why it would be necessary to extend three stacks to 200ft as HDR proposes. This likely represents an unjustified expense.
- ACSC stated that Boilers 1 & 2 have rated capacities of 137 mmBtu/hr and that annual SO_2 emissions are 241 tons at 0.37 lb/mmBtu. However, at maximum capacity, Boilers 1 & 2 can emit no more than 222 tpy.

MPCA appears to have used much of the HDR cost estimates without addressing all of these issues.

The NPS also questions the cost of a new fabric filter baghouse. HDR refers to a "Capital equipment cost provided by vendor and scaled for capacity" but does not provide the actual vendor quote.

In the absence of site-specific vendor information, NPS analyses applied the current EPA CCM workbooks for wet and dry scrubbers, ESPs, and baghouses, as well as the current S&L model for DSI with milled trona and:

- the existing ESP at 40% control
- a baghouse at 80% SO_2 control

NPS analyses applied a retrofit factor = 1.0 assuming that the new baghouses could be installed within the footprint of, or inside the shells of, the ESPs. NPS assumed equipment lives of 30 years for DSI and 20 years for a new baghouse.

The NPS analysis used the CCM to estimate operating cost savings due to ESP removal (see ESP workbook). ESP purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other costs were scaled up based upon a straight gas flow ratio. The CEPCI 2019/1987 ratio was applied to estimate total capital investment. The NPS included ACSC's $200,000 for demolition of the ESPs and estimate that saved ESP operating costs would be about $550,000/yr.

The NPS analysis used the CCM to estimate baghouse costs (see baghouse workbook). Some baghouse purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other equipment costs were scaled up based upon a straight gas flow ratio. The CEPCI 2019/1998 ratio to estimate total capital investment.

Table 3. NPS SO_2 Control Cost Estimates for DSI at ACSC

ACS CRK Boilers 1, 2 & 3	**Combined DSI w Milled Trona**			
Control Technology	**w Existing ESP**	**w BGH**	**Combined New Baghouse**	**Totals**
Capacity (MW)	43.9	43.9	43.9	
Retrofit factor	1	1	1	
CEPCI	607.5	607.5	607.5	
Capital Cost	$ 7,341,768	$ 8,703,415	$ 2,894,980	$ 11,598,395
Interest rate	3.50	3.50%	3.50%	
Control Equipment Life (yr)	30	30	20	
Capital Recovery Factor	0.0544	0.0544	0.0704	
Capital Recovery Cost	$ 399,182	$ 473,216	$ 130,599	$ 603,815
Indirect Cost/Fixed O&M	$ 312,297	$ 322,537	$ 338,298	$ 660,835
Direct Cost/Variable O&M	$ 1,054,806	$ 1,577,580	$ 262,636	$ 1,840,216
Total Annual Cost	$ 1,766,285	$ 2,373,333	$ 600,934	$ 2,712,821
Uncontrolled SO2 Emission Rate (lb/mmbtu)	0.40	0.40		0.40
Uncontrolled Tons	735	735		735
SO2 Removal Efficiency	40	80		80
Controlled SO2 Emission Rate (lb/mmbtu)	0.24	0.08		0.08
Tons Removed	294	588		588
Cost-Effectiveness	$ 6,008	$ 4,036		$ 4,614

NPS analyses show that the cost-effectiveness of adding DSI with milled trona to the existing system is $6,000/ton and with baghouse replacement is less than $5,000/ton; both of these options result in cost-effectiveness values well below MPCA's $7,600/ton threshold.

Statutory Factor 2: Time Necessary for Compliance

The NPS estimates that it would take 18 months for DSI with milled trona to be installed and operational.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACSC raises several potential concerns with respect to Dry FGD or DSI including energy use, solid waste production, and potentially shortened useful life of the boiler. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.
- Solid waste production is not a unique issue to this site and has been handled effectively in numerous instances.
- Factors that could affect boiler life can be avoided if sorbent is injected downstream of the boiler.

Statutory Factor 4: Remaining Useful Life

ACSC notes that the remaining useful life of the CRK boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs. In addition, the CCM recommends 30-year life for scrubbers unless limited by a federally-enforceable condition.

4.1.4 NO_x Four-factor Analysis

Control Selection & Efficiency

NPS review finds that the controlled emission rates presented by MPCA for SCR (see table below) are too high. SCR emissions (and efficiencies) are driven by chemical equilibrium factors. The CCM advises that SCR can achieve up to 90% control and reduce emissions down to 0.04 lb/mmbtu. In this case, NPS conservatively assumed that SCR could achieve 0.05 lb/mmBtu which would require 84% - 85% control efficiency, which is easily within the capability of SCR.

Statutory Factor 1: Cost of Compliance

On February 21, 2022, HDR submitted an "Updated Selective Non-Catalytic Reduction Performance Data for American Crystal Sugar Company Four Factor Analysis" to MPCA. ACSC's SCR costs are inflated for several reasons:

- ACSC and MPCA applied undocumented retrofit factors (1.5)
- SCR life is underestimated. The CCM recommends 20 – 25 years: while ACSC used 20 years, it also estimates that the SCR would only operate 265 days per year.[6] Such limited operation should allow SCR to operate for at least 25 years.
- ACSC stated that Boilers 1 & 2 have rated capacities of 137 mmBtu/hr and that annual NO_x emissions are 209 tons at 0.33 lb/mmBtu. However, at maximum capacity, Boilers 1 & 2 can emit no more than 198 tpy.

[6] **ACSC:** The beet sugar production process is a seasonal, or campaign-based, production process that typically runs from mid-August to June of each year. During the campaign, the boilers operate continuously, 24 hours per day 7 days per week. The boilers are shut down during summer months at the end of the processing campaign. A typical campaign runs for approximately 265 days (6,000 to 6,500 hours per year).

NPS estimates are based 10% control by SNCR and 84% - 85% control by SCR (0.05 lb/mmBtu) and are shown below.

Table 4. NPS/MPCA NO_x Control Cost Estimate Comparison for SNCR and SCR at ACSC Boilers 1 & 2

ACS CRK Boilers 1 & 2	**SNCR**		**SCR**	
Control Technology	**ARD**	**MPCA**	**ARD**	**MPCA**
Capacity (mmBtu/hr)	137	137	137	137
Retrofit factor	1.0	1.5	1.0	1.5
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$ 2,521,969	$ 3,774,769	$ 9,956,196	$ 14,757,119
Interest rate	3.50	3.50	3.50	3.50
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 177,547	$ 265,744	$ 604,341	$ 1,038,901
Indirect Cost	$ 178,682	$ 267,442	$ 606,846	$ 1,041,695
Total System Capacity Factor	0.581	0.581	0.581	0.581
Direct Cost	$ 62,984	$ 82,122	$ 136,954	$ 157,727
Total Annual Cost	$ 241,666	$ 349,565	$ 743,801	$ 1,199,421
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.33	0.33	0.33	0.33
Maximum Uncontrolled Tons	198	198	198	198
Uncontrolled Tons	115	115	115	115
NOx Removal Efficiency	25	24	85	79
Controlled NOx Emission Rate (lb/mmbtu)	0.25	0.25	0.05	0.07
Tons removed	29	28	98	91
Cost-Effectiveness	$ 8,405	$ 12,537	$ 7,622	$ 13,236

Table 5.NPS/MPCA NO_x Control Cost Estimate Comparison for SNCR and SCR at ACSC Boiler 3

ACS CRK Boiler 3	**SNCR**		**SCR**	
Control Technology	**ARD**	**MPCA**	**ARD**	**MPCA**
Capacity (mmBtu/hr)	165	165	165	165
Retrofit factor	1.0	1.5	1.0	1.5
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$ 2,562,882	$ 3,844,323	$ 11,246,337	$ 16,766,382
Interest rate	3.50	3.50	3.50	3.50
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 257,415	$ 270,640	$ 682,653	$ 1,180,353
Indirect Cost	$ 258,889	$ 272,370	$ 685,235	$ 1,183,267
Total System Capacity Factor	0.581	0.581	0.581	0.581
Direct Cost	$ 78,503	$ 87,447	$ 149,869	$ 175,778
Total Annual Cost	$ 337,392	$ 359,817	$ 835,105	$ 1,359,046
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.32	0.32	0.32	0.32
Maximum Uncontrolled Tons	231	231	231	231
Uncontrolled Tons	134	134	134	134
NOx Removal Efficiency	10	10	84	81
Controlled SO2 Emission Rate (lb/mmbtu)	0.288	0.288	0.05	0.06
Tons removed	13	13	113	109
Cost-Effectiveness	$ 25,118	$ 26,787	$ 7,368	$ 12,453

As the above tables demonstrate, SCR could reduce NO_x emissions from this facility by over 300 tons/year for $7.400 - $7,600/ton, which is at or below MPCA's acceptance threshold and well below the $10,000/ton threshold set by CO, NV, and OR.

Statutory Factor 2: Time Necessary for Compliance

The time necessary for compliance for SCR is typically four to five years after SIP approval.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACSC raises several potential concerns with respect to SNCR and SCR including energy use, ammonia storage, potential ammonia slip, and potential impacts to mercury controls. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.
- Ammonia storage and potential slip issues are not unique to this site and should be addressed by proper operation and maintenance.
- With respect to potential implications for mercury controls, the SNCR ammonia slip issue is not unique to this application. SCR is known to promote ionization/oxidation of elemental mercury to a form that can be captured by downstream control equipment. It is possible that addition of SCR upstream of the SO_2 and PM controls could result in reduced mercury emissions and/or PAC consumption/costs.

Statutory Factor 4: Remaining Useful Life

ACSC notes that the remaining useful life of the ACSC boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs. In addition, the CCM recommends 30-year life for SCR on industrial boilers unless limited by a federally-enforceable condition.

MPCA concludes that, based on the additional information provided by the facility, neither NO_x nor SO_2 controls appear to be cost-effective for either facility in this regional haze implementation period.

4.1.5 NPS Conclusions and Recommendations for American Crystal Sugar – Crookston

NPS review finds that ACSC and MPCA have overestimated the Cost of Compliance due to:

- Use of equipment life (20 years) that is too short for some controls.
- Application of unsupported retrofit factors.
- Underestimation of control efficiencies.

With respect to statutory factor one, the Cost of Compliance, after making the adjustments described above NPS analysis finds that:

- The addition of DSI (with trona) is cost-effective for SO_2 emission reductions with or without addition of a new baghouse, and
- The addition of SCR is a cost-effective option for reducing NO_x emissions from this facility.

The NPS recommends that MPCA evaluate statutory factor two, *Time Necessary for Compliance*, for addition of DSI and SCR for all three boilers. Review of statutory factors three and four finds no unusual *Energy and Non-Air Quality Environmental Impacts* related to DSI or SCR and *Remaining Useful Life* is not an issue.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of DSI with trona and a new baghouse as well as SCR to both boilers analyzed at ACSC--CRK.

- The addition of DSI with milled trona and replacement of the existing ESPs with fabric filtration on all three boilers could reduce SO_2 emissions from this facility by about 600 tons/year for less than $5,000/ton. If the ESPs are retained (which MPCA did not evaluate), about 300 tons of SO_2 could be removed annually for $6,000/ton. The cost-effectiveness of both of these DSI options is less than half the MPCA estimates and well below the MPCA cost-effectiveness threshold.
- NPS estimates that, based upon CCM guidance, SCR could reduce NO_x emissions from this facility by over 300 tons/year for $7.400 - $7,600/ton.

The NPS recommends that MPCA require the addition of DSI with milled trona and a new baghouse as well as SCR on Boilers 1, 2, and 3 at American Crystal Sugar – Crookston. By requiring implementation of identified controls MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.2 American Crystal Sugar–East Grand Forks[7]

4.2.1 Summary of NPS Recommendations for American Crystal Sugar–East Grand Forks

NPS review of the four-factor analysis conducted for American Crystal Sugar – East Grand Forks facility (ACSC--EGF) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Boilers 1 and 2. In fact, NPS analyses show that the cost of control is more economical than estimated by MPCA when analyses are adjusted in accordance with the EPA Control Cost Manual (CCM).

The addition of Dry Sorbent Injection (DSI) with milled trona and replacement of the existing Electrostatic Precipitators (ESPs) with fabric filtration on both boilers could reduce SO_2 emissions from this facility by over 700 tons/year for about $4,100/ton. If the ESPs are retained (which MPCA did not evaluate), about 360 tons of SO_2 could be removed annually for $5,600/ton. The cost-effectiveness of both of these DSI options is less than half the MPCA estimates and well below the MPCA $7,600/ton cost-effectiveness threshold.

Although MPCA did not discuss Selective Catalytic Reduction (SCR) in its final draft, it included evaluations of SCR on all three boilers in its Appendix E. However, MPCA applied a 1.5 retrofit factor with none of the required documentation. MPCA also assumed a minimal 20-year SCR life and underestimated SCR control efficiency at 80%. As a result, MPCA estimated SCR's cost-effectiveness of $8,900/ton for both boilers. Instead, NPS estimates that, based upon CCM guidance, SCR could reduce NO_x emissions from this facility by 290 tons/year for $5,100/ton.

The NPS recommends that MPCA require the addition of DSI with trona and a new baghouse as well as SCR on both boilers analyzed at ACSC--EGF. By requiring implementation of identified controls MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.2.2 Facility Characteristics

ACSC--EGF operates two Babcock and Wilcox coal-fired stoker boilers equipped with modern over-fire air (OFA) control systems. The boilers are also equipped with high-efficiency ESPs to control particulate matter (PM) emissions. The maximum rated heat input of each boiler is 356 million British thermal units per hour (mmBtu/hr). The boilers combust low sulfur subbituminous coal from the Powder River Basin[8]. The facility is located about 315 km southwest of Voyageurs National Park, a Class I area administered by the NPS. The 2017

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[7] MPCA response to NPS feedback:

MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.

[8] Based on Spring Creek Mine quality specifications, the typical mean sulfur content is 0.38 percent, and the typical mean ash content is 4.12 percent.

National Emissions Inventory (NEI) shows plantwide emissions of 676 tons of NO_x and 1,301 tons of SO_2.

4.2.3 SO_2 Four-factor Analysis

Control Selection & Efficiency

The NPS supports ACSC's selection of DSI, Spray Dry Absorption (SDA) or Circulating Dry Scrubber (CDS) in the category Dry FGD, and Wet Flue Gas Desulfurization (Wet FGD) for evaluation. (MPCA did not evaluate Wet FGD.)

In the initial (2021) four factor analysis submittal for EGF, the consulting firm HDR showed that the cost-effectiveness of DSI to reduce SO_2 emissions was below \$5,000/ton. This is quite cost-effective in spite of several factors that lead to overestimation of costs in the initial analysis. However, on February 1, 2022, HDR submitted an "Updated Dry Sorbent Injection Costs for American Crystal Sugar Company Four Factor Analysis" to MPCA revising those findings. HDR expressed concern that the ESPs at EGF, which have historically provided around 99.1% control of PM, might not be able to handle the additional loading presented by DSI and still maintain compliance with mercury and PM limits. According to HDR:

> *Therefore, the FFA was updated to enhance the PM control by adding a fabric filter baghouse. The addition of a baghouse will allow higher sorbent injection rates while maintaining compliance with the applicable PM emission limits. Further, the additional system residence time, higher sorbent injection rates, and associated sorbent filter cake in the baghouse, will allow an increased control efficiency of 70% for* SO_2.

ACSC provided little evidence to support its speculation that addition of DSI followed by the existing ESPs would result in non-compliance with particulate or mercury emission limits. On the contrary, NPS review finds substantial evidence to refute the HDR finding that DSI cannot be added without replacing the ESPs with baghouses. The S&L DSI documentation states, *"Trona, when captured in an ESP, typically removes 40 to 50% of* SO_2 *without an increase in particulate emissions…"*[9] The IPM DSI models include both ESPs and baghouses. The S&L DSI IPM model assumes that DSI with milled trona, for example, can achieve 70% removal when followed by an electrostatic precipitator (ESP) and 90% when followed by a baghouse (BGH). Also, NPS review of EPA's Clean Air Markets Data (CAMD) indicates that DSI can achieve 0.10 lb/mmbtu when followed by an ESP[10] and 0.08 lb/mmBtu when followed by a baghouse[11]. Furthermore, CAMD data for 2021 include several coal-fired Electric Generating Units (EGUs) with DSI and ESPs. (See Table 1 above).

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[9] **S&L:** Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. Trona, when captured in an ESP, typically removes 40 to 50% of SO_2 without an increase in particulate emissions, whereas hydrated lime may remove an even lower percentage of SO_2. A baghouse used with sodium-based sorbents generally achieves a higher SO_2 removal efficiency (70–90%) than that of an ESP. DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO_2/MMBtu.

[10] See the Kincaid and Waukegan entries in Table 8 below.

[11] See the Madgett entry in Table 8 below.

Statutory Factor 1: Cost of Compliance

In its 2022 submittal, HDR states:

> *American Crystal Sugar Company (ACSCC) obtained site-specific vendor quotes for Dry Sorbent Injection (DSI) equipment in order to verify estimated capital equipment and annual operating costs included in the original Four Factor Analysis (FFA) for the ACSCC East Grand Forks (EGF) and Crookston (CRK) facilities.*

However, it did not provide the vendor information supporting its costs for DSI (and a new baghouse) and NPS cannot evaluate the use of that information.

In the revised analysis, HDR's cost-effectiveness of DSI increased to above $10,000/ton. Many of the costs in ACSC's Tables 4 & 5 and HDR's Table 2 are overestimated and NPS review of the HDR submittal identifies these issues:

- ACSC used a 20-year life for DSI; the CCM recommends 30 years for SO_2 scrubbers.
- ACSC's four-factor analyses assume that DSI with milled trona and a baghouse can achieve 70% control versus 90% control in the S&L IPM model.
- HDR proposes to "Extend three stacks to 200 ft." It is unclear why it would be necessary to extend two stacks to 200ft as HDR proposes. This likely represents an unjustified expense.

MPCA appears to have used much of the HDR cost estimates without addressing all of these issues.

The NPS also questions the cost of a new fabric filter baghouse. HDR refers to a "Capital equipment cost provided by vendor and scaled for capacity" but does not provide the actual vendor quote.

Instead, NPS analyses applied the current EPA CCM workbooks for wet and dry scrubbers, ESPs, and baghouses, as well as the current S&L model for DSI with milled trona and:

- the existing ESP at 40% control
- a baghouse at 80% SO_2 control

NPS analyses applied a retrofit factor = 1.0 assuming that the new baghouses could be installed within the footprint of, or inside the shells of, the ESPs. NPS assumed equipment lives of 30 years for DSI and 20 years for a new baghouse.

The NPS analysis used the CCM to estimate ESP operating cost savings (see ESP workbook). ESP purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other costs were scaled up based upon a straight gas flow ratio. The CEPCI 2019/1987 ratio was applied to estimate total capital investment. The NPS included ACSC's $200,000 for demolition of the ESPs and estimate that saved ESP operating costs would be about $623,000/yr.

The NPS analysis used the CCM to estimate baghouse costs (see baghouse workbook). Some baghouse purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by ACSC. Other equipment costs were scaled up based upon a straight gas flow ratio. The CEPCI 2019/1998 ratio to estimate total capital investment.

Table 6. NPS SO_2 Control Cost Estimates for DSI at EGF

ACS EGF Boilers 1 & 2	DSI w Milled Trona w Existing ESP	Combined DSI w Milled Trona		
Control Technology		Combined DSI w BGH	Combined New Baghouse	Totals
Capacity (MW)	71.2	71.2		
Retrofit factor	1	1	1	
CEPCI	607.5	607.5	607.5	
Capital Cost	$ 8,709,081	$ 10,324,319	$ 2,084,998	$ 12,409,317
Interest rate (%)	3.50	3.50	3.50%	
Control Equipment Life (yr)	30	30	20	
Capital Recovery Factor	0.0544	0.0544	0.0704	
Capital Recovery Cost	$ 473,524	$ 561,347	$ 282,310	$ 843,657
Indirect Cost/Fixed O&M	$ 322,579	$ 334,726	$ 503,401	$ 838,127
Direct Cost/Variable O&M	$ 1,237,341	$ 1,783,031	$ 381,728	$ 2,164,760
Total Annual Cost	$ 2,033,445	$ 2,679,104	$ 885,129	$ 2,941,370
Uncontrolled SO2 Emission Rate (lb/mmbtu)	0.45	0.45		0.45
Uncontrolled Tons	904	904		904
SO2 Removal Efficiency	40	80		80
Controlled SO2 Emission Rate (lb/mmbtu)	0.27	0.09		0.09
Tons Removed	362	723		723
Cost-Effectiveness	$ 5,623	$ 3,705		$ 4,067

NPS analyses show that the cost-effectiveness of adding DSI with milled trona and the existing ESP had a cost-effectiveness value around $5,600/ton, and, with a new baghouse < $4,100/ton.

Statutory Factor 2: Time Necessary for Compliance

The NPS estimates that it would take 18 months for DSI with milled trona to be installed and operational.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACS raises several potential concerns with respect to Dry FGD or DSI including energy use, solid waste production, and potentially shortened useful life of the boiler. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.
- Solid waste production is not a unique issue to this site and has been handled effectively in numerous instances.

- Factors that could affect boiler life can be avoided if sorbent is injected downstream of the boiler.

Statutory Factor 4: Remaining Useful Life

ACS notes that the remaining useful life of the EGF boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs. In addition, the CCM recommends 30-year life for scrubbers unless limited by a federally-enforceable condition.

4.2.4 NO_x Four-factor Analysis

Control Selection & Efficiency

NPS review finds that the controlled emission rate presented by MPCA for SCR (see table below) is too high and efficiency too low. SCR emissions (and efficiencies) are driven by chemical equilibrium factors. The CCM advises that SCR can achieve up to 90% control and reduce emissions down to 0.04 lb/mmbtu. In this case, NPS is conservatively assuming that SCR can achieve 0.05 lb/mmBtu which would require 85% control efficiency, well within the capability of SCR.

Statutory Factor 1: Cost of Compliance

On February 21, 2022, HDR submitted an "Updated Selective Non-Catalytic Reduction Performance Data for American Crystal Sugar Company Four Factor Analysis" to MPCA. ACSC's costs for EGF are inflated for several reasons:

- No justification is provided for the retrofit factor = 1.5.
- SCR life is underestimated. The CCM recommends 20 – 25 years: while ACSC used 20 years, it also estimates that the SCR would only operate 265 days per year.[12] Such limited operation should allow SCR to operate for at least 25 years.
- Emission reductions are underestimated because ACS assumed that SCR could only achieve 80% control efficiency.

NPS estimates that SCR on each of the two boilers at EGF could reduce NO_x emissions by almost 300 tons/yr (each) at an annual cost of $1.5 million (each). NPS estimates are shown below.

[12] **ACSC:** The beet sugar production process is a seasonal, or campaign-based, production process that typically runs from mid-August to June of each year. During the campaign, the boilers operate continuously, 24 hours per day 7 days per week. The boilers are shut down during summer months at the end of the processing campaign. A typical campaign runs for approximately 265 days (6,000 to 6,500 hours per year).

Table 7. NPS/MPCA NO_x Control Cost Estimate Comparison for SNCR and SCR at EGF Boilers 1 & 2

ACS EGF Boilers 1 & 2 (each)				
Control Technology	**SNCR**		**SCR**	
Estimates by	**NPS**	**MPCA**	**NPS**	**MPCA**
Capacity (mmBtu/hr)	356	356	356	356
Retrofit factor	1	1.5	1	1.5
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$ 3,611,691	$ 5,417,537	$ 19,457,325	$ 28,837,241
Interest rate (%)	3.50	3.5	3.50	3.5
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 254,263	$ 381,395	$ 1,181,060	$ 2,030,142
Indirect Cost/Fixed O&M	$ 255,888	$ 383,833	$ 1,184,135	$ 2,033,780
Total System Capacity Factor	0.635	0.635	0.635	0.635
Direct Cost/Variable O&M	$ 129,143	$ 156,231	$ 277,115	$ 359,977
Total Annual Cost	$ 385,032	$ 540,063	$ 1,461,250	$ 2,393,757
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.34	0.306	0.34	0.34
Maximum Uncontrolled Tons	532	532	532	532
Uncontrolled Tons	338	338	338	338
NOx Removal Efficiency (%)	10	10	85	80
Controlled NOx Emission Rate (lb/mmbtu)	0.306	0.306	0.05	0.07
Tons Removed	35	35	289	269
Cost-Effectiveness	$ 10,954	$ 15,365	$ 5,063	$ 8,905

As the above table demonstrates, the NPS estimates cost-effectiveness values for SCR at less than $5,100/ton.

Statutory Factor 2: Time Necessary for Compliance

The time necessary for compliance for SCR is typically four to five years after SIP approval.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, ACS EGF raises several potential concerns with respect to SNCR and SCR including energy use, ammonia storage, potential ammonia slip, and potential impacts to mercury controls. NPS review finds that:

- The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.
- Ammonia storage and potential slip issues are not unique to this site and should be addressed by proper operation and maintenance.
- With respect to potential implications for mercury controls, the SNCR ammonia slip issue is not unique to this application. SCR is known to promote ionization/oxidation of elemental mercury to a form that can be captured by downstream control equipment. It is possible that addition of SCR upstream of the SO_2 and PM controls could result in reduced mercury emissions and/or PAC consumption/costs.

Statutory Factor 4: Remaining Useful Life

ACSC notes that the remaining useful life of the EGF boilers is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized estimated control technology costs. In addition, the CCM recommends 30-year life for SCR on industrial boilers unless limited by a federally-enforceable condition.

MPCA concludes that, based on the additional information provided by the facility, neither NO_x nor SO_2 controls appear to be cost-effective for either facility in this regional haze implementation period.

4.2.5 NPS Conclusions and Recommendations for American Crystal Sugar – East Grand Forks

NPS review finds that ACSC and MPCA have overestimated the Cost of Compliance due to:

- Use of equipment life (20 years) for some controls that is too short.
- Application of unsupported retrofit factors.
- Underestimation of control efficiencies.

With respect to statutory factor one, the Cost of Compliance, after making the adjustments described above NPS analysis finds that:

- The addition of DSI (with trona) is cost-effective for SO_2 emission reductions with or without addition of a new baghouse, and
- The addition of SCR is a cost-effective option for reducing NO_x emissions from this facility.

The NPS recommends that MPCA evaluate statutory factor two, *Time Necessary for Compliance*, for addition of DSI and SCR for both boilers. Review of statutory factors three and four finds no unusual *Energy and Non-Air Quality Environmental Impacts* related to DSI or SCR and *Remaining Useful Life* is not an issue.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of DSI with trona and a new baghouse as well as SCR to both boilers analyzed at ACSC--EGF.

- The addition of DSI with milled trona and replacement of the existing ESPs with fabric filtration on all three boilers could reduce SO_2 emissions from this facility by over 700 tons/year for about $4,100/ton. If the ESPs are retained (which MPCA did not evaluate), about 360 tons of SO_2 could be removed annually for $5,600/ton. The cost-effectiveness of both of these DSI options is less than half the MPCA estimates and well below the MPCA cost-effectiveness threshold.
- NPS estimates that, based upon CCM guidance, SCR could reduce NO_x emissions from this facility by almost 300 tons/year for $5,100/ton.

The NPS recommends that MPCA require the addition of DSI with milled trona and a new baghouse as well as SCR on both boilers at American Crystal Sugar – East Grand Forks. By requiring implementation of identified controls MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.3 Southern Minnesota Beet Sugar Cooperative[13]

4.3.1 Summary of NPS Recommendations for Southern Minnesota Beet Sugar Cooperative

NPS review of the four-factor analysis conducted for Southern Minnesota Beet Sugar Cooperative (SMBSC) finds that there are technically-feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Boiler 1. NPS analyses show that the cost of control is more economical than estimated by MPCA when analyses are adjusted in accordance with the EPA Control Cost Manual (CCM).

The NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. The Spray Dry Absorber/Circulating Dry Scrubber (SDA/CDS) option could remove 700 tons/year of SO_2 at an annual cost of $4.5 million for a cost-effectiveness value of less than $6,500/ton. NPS estimates indicate that addition of Selective Catalytic Reduction (SCR) could reduce NO_x by 800 tons/year at an annual cost of $3–$4 million resulting in a cost-effective strategy of $3,900–$5,400/ton of NO_x removed. All of these cost-effectiveness values are well below MPCA's $7,600/ton acceptance threshold.

The NPS recommends that MPCA require the addition of SDA/CDS and SCR at SMBSC. By requiring implementation of identified controls, MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

4.3.2 Facility Characteristics

SMBSC processes harvested sugar beets into beet sugar used in consumer food products. The harvested beets are processed through a series of steps including washing, beet slice, diffusion, carbonation, evaporation, and crystallization. To extract and purify the sugar, many of these processes rely upon steam. SMBSC's Boiler 1 generates steam needed for beet processing. The boiler also generates steam for SMBSC's turbine for electricity generation.

Boiler 1 is a Babcock and Wilcox Stirling boiler installed in 1975 with a maximum rated heat input of 472.4 million British thermal units per hour (mmBtu/hr). The boiler fires sub-bituminous coal as the primary fuel source and particulate is controlled by a high-efficiency electrostatic precipitator (ESP). The flue gas from the ESP is routed to a single stack. The boiler has a continuous opacity monitor and continuous emissions monitors for NO_x, SO_2, and O_2.

The facility is located near Renville, MN, about 435 km south-southwest of Voyageurs National Park, a Class I area administered by the NPS.

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[13] MPCA's response to NPS feedback:
Regarding the NO_x controls for Southern Minnesota Beet Sugar Cooperative, MPCA reiterates that there appear to be cost effective NO_x controls for this facility, but the facility disagrees with the MPCA's determination. MPCA decided to move forward with the development of this SIP submittal given that the due date of July 31, 2021, had passed. MPCA welcomes the review and input of U.S. EPA and members of the public on this topic.

4.3.3 Overarching Cost Issues

In response to earlier informal four-factor feedback SBMSC said (SMBSC July 23, 2021):

> *FLMs stated that reagent, utility, and labor costs were inflated with no basis. The basis for these parameters and the year of the estimate is listed in Appendix A of the FFA, which are reasonable representations of costs SMBSC may occur. Values were scaled up to 2020 dollars from the applicable source year assuming 3% inflation each year.*

The NPS maintains that SMBSC (and, in many cases, MPCA) increased many of these costs above their default values. The CCM only applies an inflation factor to Capital Costs. Instead, Operating Costs should be based upon site-specific costs or CCM defaults. None of the costs used by SMBSC or MPCA are specific to this facility. Escalation of costs of reagent, electricity, and labor into the future is not allowed by EPA's overnight costing method. In the absence of site-specific costs, NPS analyses use the CCM and Integrated Planning Model (IPM) default values.

4.3.4 SO_2 Four-factor Analysis

Control Selection & Efficiency

Basis for the Exclusion of Wet Flue Gas Desulfurization from the FFA

In response to earlier input, SMBSC (July 23, 2021) explained that a wet flue gas desulfurization (FGD) scrubber was not considered for the FFA because captured SO_2 would increase sulfate and potentially mercury wastewater loading. Further, SMBSC raised concerns about a new wastewater stream requiring additional wastewater treatment and consuming significant amounts of energy. The NPS analyses estimated that Wet FGD would cost almost $12,000/ton (see attached Wet FGD workbook) and is not cost-effective.

SDA and DSI SO_2 Control Efficiency Basis

In response to earlier input, SMBSC (July 23, 2021) objected to the recommendation to use control efficiencies recommended by the updated CCM chapter, which was released following the initial four-factor analysis submission. However, like most air pollution issues, regional haze is a dynamic process that changes as new information is obtained. The NPS continues to recommend that MPCA and SMBSC consider new information appropriately as part of the FLM and public review and input processes. SMBSC also stated:

> *Further, the control efficiencies are appropriate estimates. For example, the CCM states that SDA removal efficiencies range between 85-95%. Higher control efficiencies may be possible, but SMBSC will design the SDA equipment based on what has been demonstrated consistently in practice (i.e., 90%). Further, SMBSC burns subbituminous coal, which has the lowest available sulfur content. This may inhibit the SDA's ability to achieve higher control efficiencies with a lower SO_2 inlet loading compared to other coal boilers. SMBSC estimated a 70% control efficiency for DSI, which may even be too high. Even the updated CCM estimates that DSI can achieve a 50-70% SO_2 reduction.*
>
> *SMBSC will adjust the SO_2 control efficiency based on responses from equipment vendors if applicable.*

According to Barr, the SMSBC consultant: *The dry sorbent injection system requires the installation of a baghouse to accommodate the additional particulate matter from the injected sorbent and reaction byproducts.*

Barr provided no evidence to support its speculation and NPS reviewers hold that Dry Sorbent Injection (DSI) can be added without replacing the ESP with a baghouse. The Sargent & Lundy (S&L) DSI IPM documentation states, *"Trona, when captured in an ESP, typically removes 40 to 50% of* SO_2 *without an increase in particulate emissions…"* NPS analyses assumed that DSI could be added without replacing the ESP and achieve 40% control (down to 0.10 lb/mmBtu).[14] In the absence of a vendor estimate, NPS analyses conservatively assumed 80% control for DSI (down to 0.08 lb/mmBtu) with milled trona and a new baghouse.[15] (The IPM model estimates up to 90% control for this strategy.)

Table 8. Examples of coal-fired Electric Generating Units (EGUs) with DSI, CAMD 2021

State	Facility Name	Unit ID	SO_2 (tons)	Calculated Avg. SO_2 Rate (lb/MMBtu)	Heat Input (MMBtu)	Unit Type	PM Control(s)
MN	Boswell	4	391	0.025	31,545,340	Tangentially-fired	Baghouse
MI	J H Campbell	1	2,758	0.275	20,090,010	Tangentially-fired	Baghouse
MI	J H Campbell	2	2,094	0.300	13,961,840	Cell burner boiler	Baghouse
IN	R Gallagher	2	49	0.631	154,982	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
IN	R Gallagher	4	68	0.720	189,738	Dry bottom wall-fired	Baghouse (Retired 6/1/21)
WI	J P Madgett	B1	849	0.083	20,454,088	Dry bottom turbo-fired	Baghouse ESP
OK	Northeastern	3313	4,564	0.340	26,816,608	Tangentially-fired	Baghouse ESP
IL	Kincaid	2	1,083	0.093	23,285,397	Cyclone boiler	Electrostatic Precipitator
IL	Kincaid	1	808	0.093	17,366,842	Cyclone boiler	Electrostatic Precipitator
IL	Waukegan	7	501	0.095	10,522,238	Tangentially-fired	Electrostatic Precipitator
IL	Powerton	62	278	0.109	5,084,619	Cyclone boiler	Electrostatic Precipitator
IL	Powerton	61	304	0.111	5,502,464	Cyclone boiler	Electrostatic Precipitator
LA	Big Cajun 2	2B1	1,203	0.342	7,032,558	Dry bottom wall-fired	Electrostatic Precipitator
OR	Boardman	1SG				Dry bottom wall-fired	Electrostatic Precipitator

Control Equipment Life

The NPS continues to recommend that SMBSC and MPCA follow CCM recommendations with respect to control equipment life for use in cost calculations.

Spray Dry Absorbers (SDA)

The 30-year life estimate that SMSBC objects to for SDA is not a "best case scenario" as they suggest. For example, the CCM states: *Manufacturers reportedly design scrubbers to be as*

[14] See the Kincaid and Waukegan entries in Table 8.
[15] See the Madgett entry in Table 8 below.

durable as boilers, which are generally designed to operate for more than 60 years. NPS analyses relied on the CCM recommendation of a 30-year equipment life. This is likely conservative considering that the system operates on a seasonal (314 day/yr) basis. Nevertheless, even assuming a 20-year DSI life, this control would still be still quite cost-effective.

DRY SORBENT INJECTION (DSI) AND BAGHOUSES

SMSBC suggests that DSI relies on a baghouse as a “major critical component” and that baghouses have a typical equipment life of 20 years therefore making this the appropriate lifetime for a DSI system. However, a baghouse is not integral to, or required for, a DSI system, so its life should not be equated to that of DSI. NPS analyses assume that the 30-year SO_2 scrubber life would also apply to a relatively simple DSI system, and 20 years to a new baghouse.

Statutory Factor 1: Cost of Compliance

The vendor estimate relied on by SMBSC is not included in the SIP and the NPS cannot comment upon its usefulness. The cost methodology for estimates provided by SMBSC is of unknown origin. It appears that all values associated with operating costs are general (not specific to this site) and may be inflated. The NPS recommends that SMBSC use established methods and present documentation to support a robust analysis.

MPCA and SMBSC could improve this analysis by explaining the rational for requiring replacement of the existing electrostatic precipitator (ESP) with a new baghouse. This may be an unnecessary expense because the IPM DSI models include both ESPs and baghouses. Further, EPA’s Clean Air Markets data for 2021 (in Table 8) includes several coal-fired Electric Generating Units (EGUs) with DSI and ESPs.

NPS analysis used the CCM to estimate ESP operating cost savings (see ESP workbook) if the ESP is replaced. ESP purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by SMBSC. Other costs were scaled up based upon a simple gas flow ratio. The CEPCI 2019/1987 ratio was applied to estimate total capital investment. Demolition of the ESP would be about $200,000 (based on estimates for ACSC) and the estimated savings on ESP operating costs would be over $700,000/yr.

The CCM was used to estimate baghouse costs (see baghouse workbook). Some baghouse purchased equipment costs were scaled up from the CCM example using the six-tenths power rule based upon gas flow provided by SMBSC. Other equipment costs were scaled up based upon a simple gas flow ratio. The CEPCI 2019/1998 ratio was applied to estimate total capital investment.

For DSI, NPS analyses used the S&L IPM models and evaluated scenarios in which hydrated lime or milled trona was used in conjunction with the existing ESP or a new baghouse. The NPS also evaluated SDA/CDS (which includes the cost of a new baghouse) and Wet FGD using the CCM workbook.

NPS review finds that SMBSC (and MPCA) appear to have used an obsolete method to estimate costs of adding a SDA. The current CCM SDA/CDS model includes a new baghouse in its cost estimates. Finally, if the existing ESP is removed, thorough cost estimation requires deducting its operating costs from those of its replacement and adding demolition costs.

NPS analyses assumed that a new baghouse could be installed inside of the shell of the existing ESP or within its footprint and would not incur an extra retrofit penalty. Likewise, a SDA/CDS system might be installed within the footprint of the existing ESP with no additional retrofit penalty. $200,000 was added to the capital cost of replacing the ESP with a baghouse to account for demolition costs and annual ESP operating costs were subtracted. NPS calculations used equipment lives of 30 years for SO_2 scrubbers and 20 years for a new baghouse.

NPS SO_2 control cost estimates (see workbooks for details) indicate that milled trona with a new baghouse and SDA/CDS are the best options. The SDA/CDS option could remove 700 tpy of SO_2 at an annual cost of $4.5 million for a cost-effectiveness value of less than $6,500/ton.

Table 9. NPS Evaluation of MPCA cost-effectiveness scenarios for SMBSC SO_2 control options

SMBS Boiler 1	**DSI w ESP**	**DSI w BGH**	**DSI w ESP**	**DSI w BGH**	**SDA/CDS**	**WFGD**
Control Technology	**Hydrated Lime**	**Hydrated Lime**	**Milled Trona**	**Milled Trona**		
Capacity (MW)	47.24	47.24	47.24	47.24	47.24	47.24
Retrofit factor	1	1	1	1	1	1.5
CEPCI	607.5	607.5	607.5	607.5	607.5	607.5
Capital Cost	$ 7,035,466	$ 9,272,591	$ 8,076,155	$ 12,847,225	$ 44,202,984	$ 90,587,936
Interest rate (%)	3.5	3.5	3.5	3.5	3.5	3.5
Control Equipment Life (yr)	30		30		30	30
Capital Recovery Factor	0.0544		0.0544		0.0544	0.0544
Capital Recovery Cost	$ 382,528	$ 556,501	$ 439,111	$ 750,859	$ 2,404,642	$ 4,927,984
Indirect Cost/Fixed O&M	$ 309,994	$ 774,023	$ 317,820	$ 800,904	$ 2,442,551	$ 4,989,218
Direct Cost/Variable O&M	$ 830,823	$ 1,108,574	$ 896,231	$ 1,709,132	$ 2,084,642	$ 3,563,030
Total Annual Cost	$ 1,523,344	$ 2,208,791	$ 1,653,162	$ 3,030,587	$ 4,527,193	$ 8,552,247
Uncontrolled SO2 Emission Rate (lb/mmbtu)	0.52	0.52	0.52	0.52	0.52	0.52
Maximum Uncontrolled Tons/yr	1,076	1,076	1,076	1,076	1,076	1,076
Uncontrolled Tons	795	795	795	795	795	795
SO2 Removal Efficiency (%)	30	50	40	80	88	92
Controlled SO2 Emission	0.36	0.26	0.31	0.10	0.06	0.04
Tons Removed	239	398	318	636	703	733
Cost-Effectiveness	$ 6,387	$ 5,557	$ 5,199	$ 4,765	$ 6,441	$ 11,660

MPCA estimated that the cost-effectiveness of both DSI and SDA/CDS would exceed $10,000/ton and did not complete a four-factor analysis of either control option. MPCA's higher costs for DSI and SDA are partially due to due to its application of a retrofit factor = 1.5 (versus

= 1.0), and shorter equipment life. NPS estimates indicate that DSI (with trona and a new baghouse) and SDA/CDS are both cost-effective.

Statutory Factor 2: Time Necessary for Compliance

Time necessary for compliance is estimated to be 18 months for DSI with milled trona and 4 – 5 years for SDA.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

SMBSC consultant Barr cites potential increased energy usage and solid waste generation concerns. In most circumstances, energy usage is most appropriately accounted for in the Cost of Compliance analysis. The solid waste generation concerns are not unique to this site.

Statutory Factor 4: Remaining Useful Life

The CCM recommends a 30-year life for scrubbers unless limited by a federally-enforceable condition.

4.3.5 NO_x Four-factor Analysis

Control Efficiency

MPCA assumed 49% efficiency by SNCR with an estimated Normalized Stoichiometric Ratio (NSR) = 1.57. NPS application of CCM Equation 1.17 yielded NSR = 0.94. As a result NPS analyses project a 30% NO_x reduction (from CCM Figure 1.1c) down to 0.30 lb/mmBtu with much less reagent than estimated by MPCA. For SCR, MPCA assumed 92% efficiency @ 0.05 lb/mmBtu; NPS assumed 88% - 90% efficiency down to 0.05 – 0.06 lb/mmBtu.

Statutory Factor 1: Cost of Compliance

Basis for the selected retrofit factor

In the draft SIP SMBSC cost calculations for SNCR and SCR, Barr (and MPCA) included a 1.5 retrofit factor. The CCM requires specific justification and documentation to support use of factors greater than 1.0. The EPA CCM default retrofit factor = 1.0 already includes a 20%–25% markup for many of the issues cited as rationale for the higher rate. After observing Google earth photos of the facility, and in consideration of the issues described in SMBSC's July 23, 2021 submittal, NPS review finds that it appears that a higher retrofit factor may be justified for SCR installed on the roof (NPS assumed 1.5 for this calculation). However, this should not be necessary for SNCR (or SCR installed following the ESP) unless supported by a vendor. For this reason, NPS analyses used the default retrofit factor = 1.0 for those other options.

Basis and Cost for SCR Reheat

SMBSC (and MPCA) has included costs to reheat the flue gas entering the SCR in addition to applying a 1.5 retrofit factor due to the difficulty of locating the SCR above the boiler exhaust. However, MPCA's Appendix E appears to have omitted the calculations that lead to its conclusion that SCR with reheat could remove 832 tons/yr at an annual cost of $4,979,799 for cost-effectiveness of $5,986. The SIP could also be improved by a demonstration of why both of these costs (retrofit factor =1.5 and reheat costs) are necessary.

Due to the high cost of natural gas, both the MPCA and the NPS analyses included a 70%-efficient heat exchanger in the reheat system and applied CCM methods to estimate operating parameters and costs. However, in estimating the capital and operating costs of SCR, the NPS included the duct burner heat input to increase the size the SCR to handle the additional load—MPCA did not make this adjustment.

SCR Catalyst and Equipment Life Basis

In response to earlier input SMBSC replied (July 23, 2021):

> *FLMs stated that the catalyst and equipment life are underestimated compared to EPA CCM defaults. Section 4, Chapter 2 of the EPA CCM discusses catalyst and SCR life. SMBSC assumed the mid-range for the typical catalyst life guarantees (16,000–24,000 hours). While these numbers represent high dust scenarios, SMBSC will not assume that SCR catalyst will maintain proper performance without a guarantee from a vendor. This would require a detailed SCR evaluation, which is not warranted because the technology is not cost effective.*

Contrary to SMBSC's assertion, as demonstrated by both MPCA and NPS, SCR is cost-effective and a detailed SCR evaluation is warranted.

SMBSC selected "Method 2" to estimate catalyst replacement cost; this tends to produce higher cost estimates than "Method 1." 20,000 hours is an acceptable mid-range value for catalyst life for a high-dust configuration. However, SCR located following the ESP should have a longer catalyst life—NPS estimates 24,000 hours for a "clean side" application.

SMBSC also replied (July 23, 2021):

> *In addition, the CCM states that the expected SCR equipment life for industrial boilers is 20-25 years. SMBSC assumed 20 years for the SCR life because it is a reasonable approximation of what could be expected for an equipment life for purposes of the FFA and is within the default range provided by the CCM.*

According to the CCM, *"…the equipment lifetime of an SCR system is assumed to be 30 years for power plants and 20 to 25 years for industrial boilers."* NPS assumed the 25-year value which should be appropriate for a seasonal facility that only operates 314 days per year.

NPS Estimated Cost of Compliance for SNCR

Table 10. NPS estimated SNCR costs for SMSBC compared to MPCA estimates

SMBS Boiler 1	**SNCR**	
	NPS	**MPCA**
Capacity (mmBtu/hr)	472.4	472.4
Retrofit factor	1.0	1.5
CEPCI	607.5	607.5
Capital Cost	$ 4,595,032	$ 7,159,267
Interest rate (%)	3.50	3.50
Control Equipment Life (yr)	20	20
Capital Recovery Cost	$ 323,490	$ 504,012
Indirect Cost/Fixed O&M	$ 325,558	$ 507,234
Total System Capacity Factor	0.745	0.745
Direct Cost/Variable O&M	$ 488,267	$ 806,838
Total Annual Cost	$ 813,825	$ 1,314,072
Uncontrolled NOx Emissions (Tons/yr)	909	909
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.59	0.59
NOx Removal Efficiency (%)	30	49
Controlled NOx Emission Rate (lb/mmbtu)	0.42	0.30
Tons Remaining		
Tons Removed	269	447
Cost-Effectiveness	$ 3,030	$ 2,942

Significant Issues regarding SNCR Cost-Effectiveness:

- A retrofit factor greater than the CCM default value of 1.0 (which represents a 20% increase over a "greenfield" application) is likely unjustified considering the relative simplicity of typical SNCR systems. The CCM advises that:
  - If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate. According to the CCM, "You must document why a retrofit factor of "__" is appropriate for the proposed project"
- It is likely that MPCA has overestimated SNCR control efficiency and the resulting Direct Operating Costs and Tons Removed. NPS recommends application of the relationship shown in CCM Figure 1.1c.

NPS analyses estimate that addition of SNCR could reduce annual NO_x by almost 300 tons at an annual cost of about $0.8 million resulting in a very cost-effective strategy of about $3,000/ton of NO_x removed. Despite the unjustified 1.5 retrofit factor, MPCA has also estimated that addition of SNCR is very cost-effective.

NPS Estimated Cost of Compliance for SCR

The table below shows the SCR costs estimated by MPCA and NPS. The columns labeled "SCR" do not include reheat. The column labeled "Reheat" shows the costs of adding a 211 mmBtu/hr burner. The next column to the right shows costs associated with the SCR enlarged to treat the combined gas streams from the boiler and the burner. The next column to the right shows the combined costs of the reheat burner and the enlarged SCR. The cost-effectiveness of this combination is $5,381/ton. The "MPCA" column shows the actual MPCA estimates.

Table 11. NPS estimated SCR costs for SMSBC compared to MPCA estimates

SMBS Boiler 1	**SCR**		**Reheat**	**SCR+Reheat**		
Control Technology	**NPS**	**MPCA**	**NPS**	**NPS**		**MPCA**
Capacity (mmBtu/hr)	472.4	472.4	231.1528256	703.5528256		472.4
Retrofit factor	1.5	1.5	1	1		1.5
CEPCI	607.5	607.5	607.5	607.5		607.5
Capital Cost	$ 37,295,548	$ 37,416,668	$ 1,476,736	$ 33,280,344	$ 34,757,080	$ 39,367,890
Interest rate (%)	3.5	3.5	3.5	3.5		3.5
Control Equipment Life (yr)	25	20	25	25		20
Capital Recovery Cost	$ 2,263,840	$ 2,634,133	$ 89,600	$ 2,020,117	$ 2,109,716	$ 2,771,423
Indirect Cost/Fixed O&M	$ 2,268,338	$ 2,638,923	$ 148,669	$ 2,024,658	$ 2,173,327	$ 2,933,155
Catalyst Life (hr)	20,000	20,000		24,000		20,000
Catalyst Replacement Cost Method	2	2		2		2
Catalyst Replacement Cost	$ 189,384	$ 191,915		$ 278,209		$ 191,915
Direct Cost/Variable O&M	$ 886,501	$ 926,643	$ 999,551	$ 1,087,544	$ 2,087,095	$ 2,071,903
Total Annual Cost	$ 3,154,839	$ 3,565,566	$ 1,148,220	$ 3,112,202	$ 4,260,422	$ 4,979,779
Uncontrolled NOx Emissions (Tons/yr)	909	909	77.05710326	986.0571033	909	909
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.59	0.59	0.10	0.42		0.59
NOx Removal Efficiency (%)	89.8	91.5	89.8	88.1		91.5
Controlled NOx Emission Rate (lb/mmbtu)	0.06	0.05		0.05		0.05
Tons Remaining	92		8	117	117	77
Tons Removed	817	832	69	869	792	832
Cost-Effectiveness	$ 3,864	$ 4,286			$ 5,381	$ 5,986

Significant Issues regarding SCR Cost-Effectiveness:

- A retrofit factor greater than the CCM default value of 1.0 (which represents a 20% increase over a “greenfield” application) was not justified for SCR with reheat. The CCM advises that:
  - If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate. According to the CCM, “You must document why a retrofit factor of “__" is appropriate for the proposed project"
- MPCA has underestimated the life of the SCR and its catalyst.
- MPCA has not accounted for treating the increased gas flow from the reheat system and has underestimated this element of the SCR capital cost.

The NPS estimates that addition of SCR could reduce annual NO_x by about 800 tons at an annual cost of $3–$5 million resulting in a cost-effective strategy of $3,900–$5,400/ton of NO_x removed. MPCA has also estimated that addition of SCR is very cost-effective.

Statutory Factor 2: Time Necessary for Compliance

SCR operation typically requires four to five years after SIP approval, while SNCR may take up to two years.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

When evaluating statutory factor 3, SMBSC raises several potential concerns with respect to SNCR and SCR including fuel consumption and energy use. The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.

Statutory Factor 4: Remaining Useful Life

The CCM recommends 20- 25-year life for SCR on industrial boilers and 20 years for SNCR on industrial boilers unless limited by a federally-enforceable condition. NPS believes that 25 years is an appropriate estimate for the life of an SCR system on a boiler that only operates seasonally.

4.3.6 NPS Conclusions and Recommendations Southern Minnesota Beet Sugar Cooperative

NPS review finds that SMBSC and MPCA have overestimated the Cost of Compliance due to:

- Use of equipment life (20 years) that is too short for some controls.
- Application of unsupported retrofit factors.

With respect to statutory factor one, the Cost of Compliance, after making the adjustments described above NPS analysis finds that for this facility:

- The addition of DSI (with trona) is cost-effective for SO_2 emission reductions with or without addition of a new baghouse.
- The addition of SDA/CDS is also cost-effective and would provide a superior level of SO_2 emission control.
- The addition of SNCR is a cost-effective option for reducing NO_x emissions.

- The addition of SCR is also cost-effective and would provide a superior level of NO_x emission control.

The NPS recommends that MPCA evaluate statutory factor two, the Time Necessary for Compliance, addition of SDA/CDS and SCR. Review of statutory factors three and four finds no unusual Energy and Non-Air Quality Environmental Impacts related to DSI, SDA/CDS, SNCR, or SCR and Remaining Useful Life is not an issue.

In its “Table 51. NO_x control information (MPCA revision)” MPCA estimates that SNCR could remove 447 ton/yr of NO_x at $2,942/ton, and that SCR could remove 832 ton/yr of NO_x at $5,986/ton. Although the cost-effectiveness of both SNCR and SCR (as estimated by MPCA) are below MPCA’s $7,600/ton threshold, SCR does not appear in MPCA’s “Table 58. Southern Minnesota Beet Sugar Cooperative - Control measure evaluation.” Without explanation, MPCA has omitted further consideration of SCR in its Table 58 and instead states:

> No additional information provided by the facility suggests that the NO_x controls are not cost-effective for the facility in this regional haze implementation period. The MPCA maintains that the NO_x controls are cost-effective and necessary to continue making reasonable progress, but the MPCA has not reached an agreed path forward with the facility to install the NO_x controls.

MPCA appears to be depending upon SMBSC to agree to addition of SNCR with no further consideration of the more-efficient (cost-effective) SCR technology.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. The SDA/CDS option could remove 700 tons/year of SO_2 at an annual cost of $4.5 million for a cost-effectiveness value of less than $6,500/ton. The NPS estimates that addition of SCR could reduce annual NO_x by about 800 tons at an annual cost of $3–$5 million resulting in a cost-effective strategy of $3,900–$5,400/ton of NO_x removed.

5 Paper Manufacturing – Four-Factor Feedback

MPCA conducted four-factor analyses for two paper mills with the emissions shown below.

Table 12. MPCA Table 28. Q/d Analysis Emissions Data (tons/yr)

MPCA Table 28. Q/d Analysis emissions data (tons/yr)	NO_x	SO_2
Sappi Cloquet LLC	1,420.65	82.88
Boise White Paper LLC - Intl Falls	802.76	33
Totals	2,223.41	115.88

MPCA is not requiring any emission reductions from these facilities.

5.1 Sappi Cloquet LLC[16]

5.1.1 Summary of NPS Recommendations for Sappi Cloquet LLC

NPS review of the four-factor analysis conducted for Sappi Cloquet LLC supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

With respect to the NO_x evaluation on Power Boiler #9, NPS review finds that:

- Addition of SNCR is cost-effective, and
- Addition of SCR is also cost-effective and represents greater emission control.

The NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. NPS estimates indicate that addition of SCR to Boiler 9 could reduce annual NO_x by almost 300 tons/year at an annual cost of about $2 million resulting in a cost-effective strategy of about $6,500/ton of NO_x removed. By requiring implementation of identified controls MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

5.1.2 Facility Characteristics

Sappi Cloquet LLC (Sappi) is a Kraft pulp and paper mill that manufactures paper pulp, dissolving wood pulp, and fine coated paper. The facility is located near Cloquet, MN, about 175

[16] MPCA's response to NPS feedback:
MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.

km south of Voyageurs National Park, a Class I area administered by the NPS. The two emission units included in MPCA's request for information are:

- Power Boiler #9 (2016 NO_X emissions = 434 ton/yr.)
- Recovery Boiler #10 (2016 NO_X emissions = 704 ton/yr.)

It appears that these two emission units account for about 80% of mill NO_X emissions.

NPS supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled with quaternary air and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

5.1.3 NO_x Four-factor Analysis

Control Selection & Efficiency

Power Boiler #9 is a stoker grate design that burns primarily hog fuel (biomass), utilizes natural gas as a startup/supplemental fuel, is a backup combustion source for non-condensible gases, and is permitted to burn distillate oil. Based on the primary fuel use and the design of Power Boiler #9, Low-NO_x Burners (LNB) were not considered in the four-factor analysis because:

- LNB for solid fuels (like the ones at coal fired power plants) typically utilize dry solid fuel which is pulverized to a fine powder in a mill and fed pneumatically into the burners. This allows staging of air and fuel in the combustion process in order to reduce NO_x emissions. This technology is not feasible for the stoker grate hog fuel boiler at Sappi.
- LNB for natural gas and/or distillate oil are technically feasible options, but the hog fuel boiler at Sappi burns primarily hog fuel (biomass). Thus, installing LNB for natural gas and/or distillate oil would have a minor impact on NO_x emissions and therefore was not further considered in the four-factor analysis.

Based on this information, the technologies that were considered in the four-factor analysis are SCR and SNCR. The NPS supports this determination of appropriate NO_x controls for consideration.

Statutory Factor 1: Cost of Compliance

The table below shows the SNCR and SCR costs estimated by MPCA and the NPS for Sappi. All cost-effectiveness values are below $10,000/ton, and NPS estimates that the cost-effectiveness of adding SCR is below MPCA's $7,600/ton acceptance threshold.

Table 13. NPS estimated NO_x control costs for Sappi Cloquet power boiler 9 compared to MPCA estimates

Sappi Boiler 9				
Control Technology	**SNCR**		**SCR**	
	NPS	**MPCA**	**NPS**	**MPCA**
Capacity (mmBtu/hr)	430	430	430	430
Retrofit factor	1	1	1	1.33
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$ 6,068,270	$ 6,068,270	$ 22,651,621	$ 29,945,905
Interest rate (%)	3.50	3.50	3.50	3.50
Control Equipment Life (yr)	20	20	25	25
Capital Recovery Cost	$ 427,206	$ 427,206	$ 1,374,953	$ 1,817,716
Indirect Cost/Fixed O&M	$ 429,937	$ 429,937	$ 1,378,847	$ 1,822,048
Total System Capacity Factor	0.631	0.631	0.631	0.631
Catalyst Life (hr)			20,000	20,000
Catalyst Replacement Cost Method			1	1
Catalyst Replacement Cost			$ 199,786	$ 194,561
Direct Cost/Variable O&M	$ 168,063	$ 312,950	$ 485,705	$ 514,973
Total Annual Cost	$ 598,000	$ 742,887	$ 1,864,552	$ 2,337,020
Uncontrolled NOx Emissions (Tons/yr)	347	347	347	347
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.29	0.29	0.29	0.29
NOx Removal Efficiency (%)	21	25	83	80
Controlled NOx Emission Rate (lb/mmbtu)	0.23	0.22	0.05	0.06
Tons Removed	74	87	288	278
Cost-Effectiveness	$ 8,115	$ 8,562	$ 6,483	$ 8,418

Significant Issues regarding Cost-Effectiveness:

- A retrofit factor (1.33) greater than the CCM default value of 1.0 (which inherently represents a 25% increase over a “greenfield” application) was not justified. The CCM advises that:
    - If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate. According to the CCM, “You must document why a retrofit factor of “__" is appropriate for the proposed project." The MPCA retrofit factor represents a 66% increase versus a “greenfield” estimate.
- The CCM default for catalyst life is 16,000 – 24,000 hours; NPS used the MPCA 20,000-hour estimate for this application to a woodwaste-fired boiler.
- It is likely that MPCA has overestimated SNCR control efficiency and the resulting Direct Operating Costs and Tons Removed. It also appears that MPCA has overestimated the Normalized Stoichiometric Ratio (NSR) and ammonia use

for ammonia injection. NPS recommends application of the relationship shown in CCM Figure 1.1c and the CCM workbook default NSR = 1.05.
- It is likely that MPCA has underestimated SCR control efficiency and the resulting Direct Operating Costs and Tons Removed. The CCM advises that SCR can achieve emissions as low as 0.04 lb/mmbtu (and up to 90% control). NPS analyses used 0.05 lb/mmbtu (83% control) to be conservative.

The NPS estimates that addition of SNCR could reduce annual NO_x by over 70 tons at an annual cost of about $0.6 million resulting in a cost-effective strategy of about $8,100/ton of NO_x removed.

NPS estimates that addition of SCR could reduce annual NO_x by almost 300 tons at an annual cost of about $2 million resulting in a cost-effective strategy of about $6,500/ton of NO_x removed; this is below the MPCA's $7,600/ton acceptance threshold.

Statutory Factor 2: Time Necessary for Compliance
SCR operation typically requires four to five years after SIP approval, while SNCR may take up to two years.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts
Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life
The CCM recommends 20–25-year life for SCR and 20 years for SNCR on industrial boilers unless limited by a federally-enforceable condition. NPS agrees with MPCA's estimates of 20 years for SNCR and 25 years for SCR.

MPCA Conclusions
Based on the additional information provided by the facility, NOX controls no longer appear cost effective for the facility in this regional haze implementation period.

5.1.4 NPS Conclusions and Recommendations Sappi Cloquet LLC
NPS supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

For NO_x evaluation on Power Boiler #9, NPS review finds that:

- Addition of SNCR is cost-effective, and
- Addition of SCR is also cost-effective and represents greater emission control.

The NPS recommends that MPCA evaluate statutory factor two, the *Time Necessary for Compliance*, for addition of SNCR and SCR for Power Boiler #9. Review of statutory factors three and four finds no unusual *Energy and Non-Air Quality Environmental Impacts* related to SNCR or SCR and *Remaining Useful Life* is not an issue.

The NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. NPS estimates indicate that addition of SCR to Boiler 9 could reduce annual NO_x by almost 300 tons/year at an annual cost of about $2 million resulting in a cost-effective strategy of about $6,500/ton of NO_x removed. By requiring implementation of identified controls, MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

5.2 Boise White Paper

5.2.1 Summary of NPS Recommendations for Boise White Paper

NPS review of the four-factor analysis conducted for Boise White Paper (Boise) finds that, as a result of screening Boiler 2 and the Recovery Furnace, almost 688 annual tons of NO_x were not evaluated at this facility. The NPS recommends that MPCA require a four-factor evaluation of NO_X emission control opportunities for Boiler 2 and the Recovery Furnace

For Boiler 1, the NPS recommends that MPCA adjust the permitted NO_x emissions rate to more closely reflect the emission rate evaluated. If the currently permitted limit is considered, SCR may be cost effective.

For Boiler 2, the NPS estimates that addition of SCR may be very cost-effective and recommends that MPCA require a four-factor analysis for this emission unit.

5.2.2 Facility Characteristics

Boise White Paper (Boise) is wholly owned by Packaging Corporation of America (PCA) and is located in International Falls, 17 km west of Voyageurs National Park, a Class I area administered by the National Park Service. The facility is an integrated Kraft pulp and paper mill that produces commodity and specialty paper. The three emission units included in MPCA's request for information are:

- Boiler 1 (2016 NO_X emissions = 73 ton/yr.)
- Boiler 2 (2016 NO_X emissions = 366 ton/yr.)
- Recovery Furnace (2016 NO_X emissions = 322 ton/yr.)

It appears that these three emission units account for about 95% of mill NO_X emissions. In total, as a result of screening Boiler 2 and the Recovery Furnace, about 688 annual tons of NO_x were not evaluated at this facility.

Facility-wide SO_2 emissions were 33 tons.

Boise Boiler #1 was originally commissioned as a coal-fired boiler and has been converted to only burn natural gas. The boiler produces steam to generate electricity and provide heat for other processes at the plant. Exhaust from the sludge dryer may also vent to Boiler #1. The boiler is also a backup combustion source for non-condensable gases (NCG) which are the exhaust gases from the pulp digestion and black liquor solids (BLS) evaporation processes. The amount of NCG burned in Boiler #1 is limited by the facility air permit. Good combustion practices are utilized for Boiler #1 through a combination of several efforts, including control strategy, boiler monitoring, and training.

5.2.3 Boiler #1 NO_x Four-factor Analysis

Control Selection

Three types of NO_x emission controls were evaluated for Boise Boiler 1:

- LNB/OFA + FGR
- SNCR
- SCR

The SNCR analysis is not included in MPCA SIP Table 44 but was included in NPS review.

Statutory Factor 1: Cost of Compliance

MPCA presented the analyses shown in its Table 51 below.

Table 14. Minnesota draft SIP Table 51. NO_x control information (MPCA revision)

Facility	Emission Unit	Control Measure	Emission Reduction (tpy)	Capital Costs ($)	Annual Costs ($)	Cost Effectiveness ($/ton)
Boise White Paper	Boiler 1	LNB/OFA + FGR	58	$11,144,531	$1,557,544	$26,649
		SCR	66	$8,031,851	$905,022	$13,783

In addition, MPCA provided an analysis of SNCR using methods developed by EPA in its Control Cost Manual (CCM) and determined that SNCR could reduce NO_x emissions by 38 tons/yr at an annual cost of about $250,000 for a cost-effectiveness value of just over $6,600/ton of NO_x removed, which is below the MPCA $7,600/ton cost-effectiveness threshold.

The NPS applied the CCM SNCR and SCR workbooks with the parameters shown below, including application of the relationship provided in CCM SNCR Figure 1.1c to estimate SNCR control efficiency. NPS analyses assumed that SCR on this natural gas-fired boiler would have a 25-year equipment life and a 24,000-hour catalyst life and could achieve 85% control.

Table 15. Comparison of NPS and MPCA Cost Calculations for Boise Boiler #1

Emission Unit	**Boiler #1**			
	NPS	**MPCA**	**NPS**	**MPCA**
Control Technology	**SNCR**		**SCR**	
Capacity (mmBtu/hr)	398	398	398	398
Retrofit factor	1	1	1	1
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$ 2,522,567	$ 2,658,260	$ 8,031,851	$ 8,031,851
Interest rate (%)	3.50	3.50	3.50	3.50
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 177,589	$ 187,141	$ 487,533	$ 565,442
Indirect Cost/Fixed O&M	$ 178,724	$ 188,338	$ 490,542	$ 568,451
Catalyst Life (hours)			24,000	20,000
Direct Cost/Variable O&M	$ 59,483	$ 61,518	$ 285,762	$ 336,571
Total Annual Cost	$ 238,207	$ 249,856	$ 776,305	$ 905,022
Uncontrolled NOx Emission Rate (lb/mmBtu)	0.13	0.13	0.13	0.13
Uncontrolled Tons	95	95	94	95
NOx Removal Efficiency (%)	19	40	85	70
Controlled NOx Emission Rate (lb/mmbtu)	0.11	0.08	0.02	0.04
Tons Removed	18	38	79	66
Cost-Effectiveness	$ 13,122	$ 6,608	$ 9,781	$ 13,783

NPS estimates that addition of SCR could reduce NO_X emissions by almost 80 tons/yr at a annual cost of $0.8 million at $9,800/ton. While this cost-effectiveness value is above the MPCA threshold, it is below the $10,000/ton threshold used by CO, NV, and OR. Statutory Factor 2: Time Necessary for Compliance

Installation of SNCR typically requires up to two years while time necessary for compliance for SCR is typically four to five years after SIP approval. Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

MPCA used a 20-year life for SNCR and SCR.

Boise Boiler #2 was originally commissioned as a coal-fired boiler This emission unit is a stoker grate design which produces steam to generate electricity and provide heat for other processes at the plant. The boiler burns primarily hog fuel (biomass which is primarily bark and wood refuse from the facility de-barking process) and is also permitted to burn wastewater treatment plant sludge, paper, and natural gas. The boiler is also a backup combustion source for NCG. The amount of NCG burned in Boiler #2 is limited by the facility air permit. Particulate matter emissions from the power boiler are controlled by multiclones and a high-efficiency electrostatic precipitator (ESP). Boiler #2 does not have add-on NO_X controls but does use staged and overfire air to manage the generation of NO_X The boiler does not have add-on SO_2 controls but burns low sulfur fuels and the wood ash provides some dry scrubbing of SO_2 when NCGs are burned concurrently. This boiler appears to be very similar to Boiler 9 at Sappi Cloquet for which MPCA required a four-factor NO_X control analysis.

5.2.4 Boiler #2 NO_x Four-factor Analysis

MPCA screened Boiler 2 from four-factor analysis based on a 2013 BACT analysis and the presence of a more stringent NO_x emissions limits than found in a review of permit limits for similar sources.

However, NPS has reviewed three other hogged fuel boilers similar to Boiler #2 at paper mills, including the Sappi mill in Cloquet, MN where SNCR and SCR were evaluated by the state for NO_x reductions. Two of those boilers (PCA @ 0.19 lb/mmBtu in Wallula, WA and Nippon Dynawave @ 0.23 lb/mmBtu in Longview, WA) have NO_x emission rates that are lower than the 0.25 lb/mmBtu NO_X emission rate for Boiler 2 at Boise White.

In its July 2021 clarification memo, EPA advised that states must show why additional emission reductions are not necessary to make reasonable progress. Section 2.3 addressed the analytical expectations for "effectively controlled" determinations:

> *The underlying rationale for the "effective controls" flexibility is that if a source's emissions are already well controlled, it is unlikely that further cost-effective reductions are available.* ***A state relying on an "effective control" to avoid performing a four-factor analysis for a source should demonstrate why, for that source specifically, a four-factor analysis would not result in new controls and would, therefore, be a futile exercise.***

MPCA has not demonstrated that conducting a four-factor analysis would be a "futile exercise." In fact, NPS will show that post-combustion NO_X controls on Boiler 2 could be cost-effective. The NPS recommends that MPCA or require a four-factor evaluation of NO_X these emission control opportunities.

Statutory Factor 1: Cost of Compliance

In the absence of a four-factor analysis by MPCA, NPS used information from the draft SIP.

- Based upon CCM Figure 1.1c, SNCR is estimated to reduce NO_x emissions by 20% from a baseline emission rate of 0.25 lb/mmBtu.
- SCR is assumed to be able to achieve 80% NO_X reduction down to 0.05 lb/mmBtu for this woodwaste-fired boiler.
- An SCR catalyst life = 20,000 hours for this woodwaste-fired boiler.

Table 16. NPS Control Cost Estimates for Boise Boiler #2

Emission Unit	**Boiler #2**	
Control Technology	**SNCR**	**SCR**
Capacity (mmBtu/hr)	400	400
Retrofit factor	1	1
CEPCI	607.5	607.5
Capital Cost	$ 3,964,043	$ 21,253,112
Interest rate (%)	3.50	3.50
Control Equipment Life (yr)	20	25
Capital Recovery Cost	$ 279,069	$ 21,253,112
Indirect Cost/Fixed O&M	$ 280,852	$ 1,290,064
Catalyst Life (hours)		20,000
Direct Cost/Variable O&M	$ 110,882	$ 1,293,967
Total Annual Cost	$ 391,735	$ 1,646,615
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.25	0.25
Uncontrolled Tons	401	401
NOx Removal Efficiency (%)	22	80
Controlled NOx Emission Rate (lb/mmbtu)	0.20	0.05
Tons Removed	88	321
Cost-Effectiveness	$ 4,462	$ 5,132

NPS analysis determined that SNCR could reduce NO_x emissions by 88 tons/yr at an annual cost of about $392,000 for a cost-effectiveness value of almost $4,500/ton of NO_x removed.

For SCR, NPS determined that SCR could reduce NO_x emissions by 320 tons/yr at an annual cost of $1,646,000 for a cost-effectiveness value of about $5,100/ton of NO_x removed.

Statutory Factor 2: Time Necessary for Compliance

Installation of SCR typically requires four-to-five years.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

MPCA used a 20-year life for SNCR and for SCR. The CCM recommends 20 – 25 years for SCR; NPS analyses assumed 25 years for this woodwaste-fired boiler.

Recovery Furnace: This emission unit burns strong BLS that are generated in the kraft pulp mill chemical recovery process. Weak BLS, which is generated as part of the pulping and washing processes, are concentrated in evaporators to make strong BLS. The strong BLS is then charged to the Recovery Furnace where the organic portion of the BLS is burned to produce steam to generate electricity and provide heat for other processes at the plant. The cooking chemicals collect as molten smelt at the bottom of the boiler. The amount of BLS burned in the Recovery

Furnace is limited by the facility air permit. The Recovery Furnace is a primary source of all criteria pollutant emissions, as well as sulfuric acid (H2SO4), total reduced sulfur (TRS), and Hazardous Air Pollutants (HAP). Particulate matter emissions from the Recovery Furnace are controlled by a high-efficiency ESP. The Recovery Furnace does not have add-on NOX controls but does use staged air injection to manage the generation of NOX.

MPCA screened the Recovery Furnace from four-factor analysis based on a 2013 BACT analysis and the presence of a more stringent NO_x emissions limits than found in a review of permit limits for similar sources.

NPS notes that potentially more-effective quaternary air combustion controls are in use (at the Sappi Cloquet mill in Minnesota) to reduce NO_X from the Recovery Furnace. While the recovery furnace uses staged air combustion to manage the generation of NO_x, it is not clear if that includes quaternary air.[17] If not, the NPS recommends that MPCA investigate its addition.

5.2.5 NPS Conclusions and Recommendations Boise White Paper

MPCA's Table 33 shows that Boise emitted 803 tons of NO_x. Of this total, only 73 tons of NO_x are attributed to Boiler #1, the only unit selected for four-factor evaluation. MPCA Table 33 shows that Boiler #2 has NO_x emissions of 401 tons/yr and that the Recovery Furnace has NO_x emissions of 323 tons/yr. Emissions from each of these units is several times greater than the emissions that were evaluated.

- For Boiler #1 the NPS has determined that SCR may be cost effective relative to the $10,000/ton threshold used by CO, NV, and OR.
- In the absence of a four-factor analysis and based upon available information, the NPS estimates that addition of SCR to Boiler #2 may be very cost-effective. The NPS recommends that MPCA require a four-factor analysis for this emission unit.
- The NPS also recommends that MPCA evaluate the addition of quaternary air to the Recovery Furnace (if it is not already so-equipped).

[17] SUN BIO MATERIAL (U.S.) COMPANY, PSD PERMIT APPLICATION, November 2018: The most widely used combustion modification approach in recovery boilers is commonly referred to as "quaternary air/staged combustion." This technology involves four stages of combustion air supplied at successively higher points in the body of the furnace. Quaternary Air/Staged Combustion minimizes NOx emissions by maintaining the minimum combustion temperature possible at each successive stage in the furnace to combust the black liquor solids while maintaining high sulfur reduction efficiencies, good bed stability, and uniform velocities after the furnace to minimize high temperatures and fouling. Primary air is used for bed stability, efficient carbon burnout, and high sulfur reduction efficiencies. Secondary (low and high) air ensures even air distribution over the char bed for pyrolysis and volatiles burning. NCG gas can be mixed with high secondary air, which provides air to the start-up burners. Tertiary air is the over-fire air over black liquor sprays and provides air to load-carrying burners. Finally, quaternary air is the air staging register at the upper furnace for NOx reduction. Moreover, the "Quaternary Air/Staged Combustion" technology employed on all modern recovery boiler systems already minimizes NO_X emissions while maintaining high reduction efficiencies, good bed stability, and uniform velocities.

6 Taconite – Four-Factor Feedback[18]

6.1 Overarching Taconite

At the MN taconite facilities, iron ore from mines along the Mesaba Iron Range is separated from taconite (a low-grade iron ore) using magnetism. The taconite powder with the iron in it is called concentrate which is rolled with clay inside large rotating cylinders. The cylinders cause the powder to roll into marble-sized balls that are then dried and heated until they are white hot. The balls become hard as they cool and become taconite pellets which are shipped to steel mills to be melted down into steel.[19]

On February 6, 2013, U.S. EPA promulgated a Taconite Regional Haze FIP that included BART limits for taconite furnaces subject to BART in Minnesota with an effective date of March 8, 2013.[20] On April 12, 2016, U.S. EPA finalized the revisions to the 2013 FIP and the final rule (2016 FIP) was effective on May 12, 2016.[21] EPA's 2016 FIP contained this:

> *We expect Minnesota and Michigan to reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods, but reject the technology as BART for the Minnesota and Michigan taconite facilities at this time.*

MPCA initially selected six taconite plants for four-factor analyses; their 2017 emissions (from the National Emissions Inventory—NEI) are shown below. (All emissions except Hg are in ton/yr; Hg is in lb/yr.) These facilities are located between 85 and 150 km south of Voyageurs National Park and within 300 km of Isle Royale National Park, both Class I areas administered by the National Park Service (NPS).

[18] MPCA responses to NPS feedback:
MPCA added additional detail to Section 2.3.5 regarding the current FIP limits applicable to the taconite companies and a comparison of reported emissions data for recent years. MPCA also added additional clarification to Section 2.6.1 regarding how the MPCA estimated the reductions due to the FIP limits.
MPCA appreciates the suggestion to consider potential emission reduction measures from a multi-pollutant perspective. MPCA believes that is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts.

[19] Taconite | Minnesota DNR (state.mn.us)
[20] See 78 Fed. Reg. 8706 (February 6, 2013).
[21] See 81 Fed. Reg. 21672 (April 12, 2016).

Table 17. Recent annual emissions from Minnesota Taconite facilities, NEI 2017

Facility Name	Hg, lb/yr	NO_x, tpy	PM10-PRI, tpy	PM25-PRI, tpy	SO_2, tpy	NO_x+ PM10+ SO_2, tpy	Distance to NPS Class I Area, km	(NO_x+ PM10+ SO_2)/d
Hibbing Taconite Co	149	3,981	1,567	400	824	6,372	100	64
ArcelorMittal Minorca Mine Inc	75	3,063	567	173	136	3,766	85	44
United Taconite LLC - Fairlane Plant	190	3,743	595	412	275	4,613	108	43
Northshore Mining Co–Silver Bay	22	2,169	461	327	1,539	4,169	147	28
US Steel Corp–Minntac	173	6,481	2,788	2,084	1,207	10,476	85	123
US Steel Corp–Keetac	90	5,009	533	411	533	6,075	109	56
Totals	700	24,446	6,511	3,807	4,514	35,471		358

Based on emissions relative to distance to NPS managed Class I areas, MN ranks #9 in the US, with the taconite facilities comprising more than half of those impacts. (The taconite plants alone would rank #22 as a "state."

MPCA subsequently decided that no four-factor analyses or emission reductions were required for any of these facilities. The paragraph below (United Taconite—Fairlane) is an example of MPCA's rationale from the draft SIP:

> *These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis. Regarding NO_x emissions, the emission units installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission units were determined to be BART, meaning no add-on controls were required, both emission units are subject to an hourly SO_2 emission rate limit and fuel sulfur content requirements established in the Taconite FIP. Given the level of control required for these emissions units, the MPCA determined that it was unlikely that there are further available reasonable controls for these emission units and removed them from further analysis for this implementation period.*

NPS review and analysis demonstrates that controls that are more effective than the current controls are technically feasible, cost-effective, and may be considered reasonable.

MPCA may also be relying upon two other issues related to the taconite companies:

- Analyses conducted by U.S. EPA that determined what emission reductions were BART for the indurating furnaces at taconite facilities in Minnesota, as discussed earlier in Section 2.3.5 regarding sources that are effectively controlled are referenced and relied on. The BART analyses conducted by U.S. EPA were included in the Taconite Regional Haze FIPs promulgated in 2013 and 2016.
- According to MPCA, U.S. EPA and the Minnesota taconite facilities have been in continued settlement discussions since the promulgation of these FIPs, as discussed in SIP Section 1.3, most recently resulting in revisions to the FIP requirements for U.S. Steel–Minntac in 2020. While the MPCA is not included in the settlement discussions

between U.S. EPA and the Minnesota taconite facilities, the MPCA expects that U.S. EPA's current analysis is both sound and does not require an update for this implementation period given that U.S. EPA continues to evaluate the specific requirements of the FIP, including the associated BART emission limits.

EPA's previous BART determinations are no longer current (some of the facilities may have changed fuel mixtures and/or pellet characteristics) and warrant revisiting, especially with respect to EPA's 2016 comments regarding SCR with reheat.

The ongoing negotiations among EPA and the Minnesota taconite facilities do not exempt the taconite facilities from review in this planning period. In its 11/01/2021 letter to Wyoming, EPA stated:

> *Wyoming states that it did not conduct a four-factor analysis for the Wyodak facility due to ongoing first planning period litigation. 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.*

6.2 United Taconite LLC–Fairlane Plant

6.2.1 Summary of NPS Recommendations for United Taconite LLC–Fairlane Plant

NPS review of the four-factor analysis conducted for Cleveland Cliffs' United Taconite—Fairlane Plant (UTAC) finds that NO_x, SO_2, and PM emissions from UTAC's Lines #1 & #2 are not effectively-controlled. Further, NPS review finds that:

- Application of tail-end SCR (installed after the existing wet scrubbers) at UTAC could cost-effectively reduce NO_x emissions by over 2,500 tons/yr.
- On their own, opportunities to reduce SO_2 emissions with a modern scrubber and fabric filter or ESP are well above the threshold for consideration even when adjusted for conformance with CCM methods. However, an integrated approach that precedes tail-end SCR with dry scrubbing and a fabric filter would minimize catalyst fouling (improving the technical feasibility of SCR) while drastically reducing PM emissions as well as reducing SO_2 emissions. This would be a far superior approach from an emissions reduction and cost effectiveness perspective with the potential to reduce haze causing emissions by thousands of tons per year in a cost-effective manner (Table 20).

The NPS recommends that MPCA require all taconite facilities originally selected for four-factor analysis to conduct four-factor analyses evaluating how an integrated approach to emission control improvements could reduce visibility-impairing emissions. Given both the scale and proximity of haze-causing emissions from taconite facilities, this may be the single best strategy available to MPCA for reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

6.2.2 Facility Characteristics

UTAC is located 108 km southwest of Voyageurs National Park. Of the six taconite facilities identified by MPCA for four-factor analysis, only Cleveland Cliffs submitted one for its UTAC plant. In that submittal, the company included this disclaimer:

> *The NOx Four-Factor analysis evaluated Selective Catalytic Reduction (SCR) with reheating of the exhaust gases using a conventional duct burner. It is important to note that the use of SCR with reheat has not been demonstrated on taconite furnaces or similar sources. Therefore, this technology does not meet the definition of technically feasible. However, according to EPA's 2016 Final Federal Implementation Plan (FIP),22 EPA expects Minnesota to reevaluate SCR with reheat as a potential option for reasonable progress in future planning periods. It is only due to this statement by EPA that the SCR with reheat control technology is included in the analysis; UTAC does not concur that SCR with reheat is considered technically feasible.23*

The NPS observes that, for the purposes of four factor analysis, a technology need not have been demonstrated on a specific industry to be "technically feasible"—it must only be available (which SCR is) and applicable (which SCR may be).

According to MPCA, lines 1 and 2 at UTAC were BART-eligible emission units and BART emission limits on NO_x and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first Regional Haze Implementation Period. Lines 3, 4, and 5 can burn coal, petroleum coke, natural gas and distillate oil. These emission units utilize existing wet scrubbers for SO_2 control.

Emission units are subject to a NO_x emissions limit (1.5-3.0 lb NO_x/MMBtu for each line, fuel dependent, as a 30-day rolling average) established in the Taconite FIP dated April 12, 2016. These emission units required add-on controls, low-NO_x burners, to meet the NO_x limits.

Based upon data submitted by UTAC, annual average NO_x emission rates were 1,325 tons @ 1.83 lb/mmBtu for Line 1 and 1,874 tons @ 1.22 lb/mmBtu for Line 2. Additionally, these emission units are subject to an SO_2 emissions limit (529 lb SO_2/hr, averaged across both lines as a 30-day rolling average and a 1.50 percent sulfur content limit for any coal burned as a monthly block average) established in the Taconite FIP dated April 12, 2016. In the 2016 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

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[22] EPA April 12, 2016 Federal Register: We expect Minnesota and Michigan to reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods, but reject the technology as BART for the Minnesota and Michigan taconite facilities at this time.

[23] Regional Haze Four-Factor Analysis for NO_x and SO_2 Emissions Control
Line 1 Pellet Indurating Furnace EQUI 45/EU 040
Line 2 Pellet Indurating Furnace EQUI 47/EU 042
Prepared for United Taconite LLC – Fairlane Plant July 31, 2020

UTAC reports that the existing wet scrubbers are 25% effective at reducing SO_2. Based upon data submitted by UTAC, annual average SO_2 emission rates were 59.7 tons @ 0.08 lb/mmBtu for Line 1 and 215.4 tons at 0.18 lb/mmBtu for Line 2. The existing wet scrubbers are also 94% effective at reducing PM. (These NPS calculated values are based upon Appendix B of UTAC's four-factor estimate that Line 1 PM emissions are almost 1,500 tons/year and Line 2 PM emissions exceed 3,400 tons/year. MPCA reports that Line 2 emitted 94 tons of $PM_{2.5}$ in 2017.) Considering that modern particulate controls can remove 99.9% of emissions and modern SO_2 scrubbers can achieve up to 99% control, it is reasonable to conclude that more-effective controls for these pollutants may be feasible.

6.2.3 NO_x Four-factor Analysis

SCR – Post-Scrubber with Conventional Duct Burner Reheat

UTAC states that: According to EPA's 2016 Final FIP, a taconite facility in Sweden, LKAB, has implemented and operated an SCR with reheat through a conventional duct burner on a taconite indurating furnace. However, EPA has stated the following:

> *Alstom, the SCR vendor for LKAB, declined twice to bid on an SCR with reheat at Minntac, citing technical difficulties with the SCR with reheat at LKAB. These difficulties included operating within the narrow temperature range required by SCR with reheat. Further, LKAB is looking into process optimization and better burners to reduce NO_x as opposed to installing another SCR with reheat in the future.*

That information was specific to a different facility that burned different fuels over nine years ago and may very well be outdated or inapplicable. The NPS recommends contacting a SCR vendor regarding application to current UTAC operations.

UTAC also raises concerns regarding the application of SCR on taconite furnaces due to the differences from utility boilers with respect to gas composition, dust loading, and chemistry. Specifically, UTAC states that:

> *The most serious issues yet to be resolved with SCR on furnaces include the formation of SO3 in the reactor, the ability to inject ammonia at proper molar ratio under non-steady state conditions, the creation of visibility impairing pollutants, the increased oxidation of mercury, the creation of a detached plume, catalyst life, catalyst poisoning, fouling of the bed, and system resistance. Some of these issues, discussed in more detail below, could affect the validity of SCR with reheat control technology and would require extensive testing prior to installation and operation on an existing indurating furnace.*

Sulfur Dioxide and Sulfuric Acid

NPS review finds that the SO_2 concentrations in the gas stream exiting the existing 25%-efficient wet scrubbers is an order of magnitude lower than encountered by SCR on a typical coal-fired boiler. SCR in a tail-end configuration would also be exposed to much lower concentration of particulate and the reheated gas stream exiting the SCR would be well above the acid dewpoint.

NO_x Variability and Ammonia Slip

With respect to concerns raised by UTAC regarding NO_x variability and ammonia slip, the NPS notes that the reference cited is from 2006 and is based upon a high dust configuration SCR at a cement plant. As such it may not be relevant. Modern process controls and a much cleaner tail-end SCR location should be capable of better performance. The EPA Control Cost Manual (CCM) provides this more up-to-date information:

> *In the cement industry, pilot tests in the 1970s and 1990s showed that SCR could be a feasible control technology for cement kilns. Building on that experience, SCRs were first installed in Europe in 2001. Today, SCR has been successfully implemented at seven European cement plants in Solnhofer, Germany (operated from 2001 until 2006), Bergamo, Italy (2006), Sarchi, Italy (2007), Mergelstetten, Germany (2010), Rohrdorf, Germany (2011), Mannersdorf, Austria (2012), and Rezatto, Italy (2015). As of 2015, there is only one cement plant in the U.S. that has installed an SCR. This SCR began operation in 2013 and is installed after an electrostatic precipitator. The control efficiency for the system is reported to be about 80 percent, which is consistent with SCR applications on European kilns. SCRs have not seen widespread use in the U.S. cement industry mainly due to industry concerns regarding potential problems caused by high-dust levels and catalyst deactivation by high sulfur trioxide (SO3) concentrations from pyritic sulfur found in the raw materials used by U.S. cement plants. The SO3 could react with calcium oxide in the flue gas to form calcium sulfate and with ammonia to form ammonium bisulfate. The calcium sulfate could deactivate the catalyst, while the ammonium bisulfate could cause catalyst plugging. There have been concerns expressed about the potential for catalyst poisoning by sodium, potassium, and arsenic trioxide. Finally, other concerns expressed are that dioxins and furans may form in the SCR due to combustion gases remaining at temperatures between 450 degrees Fahrenheit (°F) and 750°F. These and other concerns regarding the implementation of SCR to the cement industry are discussed in detail in "Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns". Due to the small number of SCRs installed at cement plants, information on capital and operating costs for SCRs at cement plants is limited. The installation and operating costs for the SCR installed at the U.S. plant in 2013 are not publicly available at this time. In general, we expect the capital and operating costs would be higher than for low-dust applications due to the need to install catalyst cleaning equipment for SCR systems installed in high-dust configurations and for heating the flue gas in low-dust, tail-end configurations.*

Mercury Oxidation

UTAC raises mercury oxidation as a potential concern saying:

> *In the case of mercury, the SCR oxidizes mercury from its elemental form. Given the propensity for oxidized mercury to deposit near its emission point, the increase in mass of oxidized mercury emissions is expected to result in more local deposition (i.e., increased loading of mercury) and most certainly*

within northeast Minnesota. An increase in mercury loading to northeast Minnesota is inconsistent with the Statewide Mercury Total Maximum Daily Load (TMDL) study that requires a reduction in loading in order to reduce fish tissue mercury concentrations in the area. In addition, a wet scrubber would be required to control the oxidized mercury formed in the SCR.

NPS review finds that UTAC emitted 190 pounds of mercury in 2017, which ranked 49th highest in the US (2017 NEI). A co-benefit of SCR is its ability to oxidize elemental mercury to a form that is more-easily captured in follow-on controls. The NPS recommends that UTAC focus on the potential opportunity to reduce all forms of mercury emissions. Continued dispersion of mercury emissions over a wide area is a significant and ongoing concern for current controls.

Indurating Furnace Exhaust Dust

UTAC expressed concerns that constituents in the indurating furnace exhaust gas stream could adversely affect the SCR catalyst and increase adverse pollutant introduction to the exhaust stream. However, tail-end SCR being evaluated in this case is exposed to much lower concentrations of particulates and SO_2 than conventional SCR on a coal-fired boiler, for example.

The NPS appreciates that UTAC evaluated three SO_2 control scenarios that included enhanced particulate controls.

The advantages of tail-end SCR are described by the CCM:

An SCR reactor located downstream of the air heater, particulate control devices, and flue gas desulfurization (FGD) system ("low-dust" or "tail-end" configuration) is essentially dust- and sulfur-free but its temperature is generally below the acceptable range.
A tail-end system may have higher capital and operating costs than the other SCR systems because of the additional equipment and operational costs associated with flue gas reheating and heat recovery. However, these costs are in part offset by reductions in catalyst costs. Tail-end units require less catalyst because they can use catalysts with smaller pitch and higher surface area per unit volume. Tail-end SCR typically require only 2 layers of catalyst, although some use four half-layers of catalyst to allow for greater flexibility for catalyst replacement. In addition, because there is less fly ash, catalyst poisons, and SO_2 in the flue gas for tail-end units, the catalyst lifetime is significantly increased, and less expensive catalyst may be used. Some sources have reported catalyst lifetimes for tail-end SCRs to be over 100,000 hours. The tail-end SCRs may also have longer lifetimes due to the lower operating temperatures and lower levels of dust and SO3.

Addition of SCR with reheat in a tail-end configuration at UTAC would mitigate the concerns about catalyst fouling, poisoning, and degradation. Nevertheless, NPS analyses assumed tail-end SCR life of 20 years and catalyst life of 16,000 hours (the lower ends of the ranges recommended by the CCM for SCR on industrial boilers). NPS also applied the maximum recommended retrofit factor = 1.5. Considering the almost 5,000 tons of particulate emitted by

UTAC annually, the NPS recommends an integrated approach (as evaluated by UTAC and discussed in the SO_2 control section below) to reducing particulate, SO_2 and NO_x.

Statutory Factor 1: Cost of Compliance

NPS review finds that UTAC has overestimated the capital costs by overestimating the system heat input. Instead, NPS calculations included a 70%-efficient heat exchanger to reduce natural gas reheat requirements. Not only did this reduce operating costs dramatically, but the reduced system heat input also resulted in the much lower SCR capital costs.

The NPS evaluated the addition of SCR with reheat by making the following assumptions:

- Natural Gas = $3.90/scf (used by MPCA in other analyses)
- Urea 50% Solution = $1.66/gal (used by MPCA in other analyses)
- Estimated operating life of the catalyst ($H_{catalyst}$) = 16,000 hr (NPS used the lower end of the CCM catalyst life estimate due to the unproven nature of this application. UTAC assumed 8,000 hours which is less than the 16,000-hour lower end of the CCM range.)
- Catalyst cost ($CC_{replace}$) = $227/cf (CCM default) (UTAC used $248.05 based on inflating the CCM value. Instead, UTAC should use an actual, site-specific current value.)
- Interest Rate = 3.5% used by MPCA in other analyses--UTAC used a 4.75% interest rate.
- Markup on capital cost (Retrofit Factor) = 50% due to unproven application of SCR to taconite furnaces.
- Equipment Life = 20 years. NPS used the lower end of the CCM equipment life estimate due to the unproven application of SCR to taconite furnaces. (UTAC also used 20 years.)
- SCR Control Efficiency = 80% despite the clean, tail-end location with gas stream heated to CCM 650°F default. (UTAC used 50% based upon a 2006 report on SCR applied to cement kilns in a high-dust configuration.)
- The Chemical Engineering Plant Cost Index (CEPCI) for 2019 and used by MPCA was 607.5.

NPS analyses based SCR "Data Inputs" on the following:

- Maximum heat input rate (QB)
    - In addition to the heat input (190 mmBtu/hr for Line 1 and 400 mmBtu/hr for Line 2) from the induration furnace burners, the heat input from the duct burners that would be added to reheat the gas stream exiting the existing wet scrubbers (at 140°F for Line 1 and 136°F for Line 2) was included. NPS applied the Auxiliary Fuel Use Equation 2.21 from CCM 7th Ed November 2017 - Chapter 2 Incinerators and Oxidizers and estimated the additional duct burner heat input required to raise the SCR inlet temperature to 650°F (the CCM default value). Addition of a 70% efficient heat exchanger to reduce natural gas use was assumed. An additional 1,771 scfm gas is estimated as necessary to reheat Line 1 and 3,587 scfm for Line 2. The induration furnace + reheat total heat input rate

is estimated to = 400 mmBtu/hr for Line 1 and 622 mmBtu/hr for Line 2. These heat input rates are critical parameters in estimating the capital costs of the SCR systems.
    - UTAC did not include a heat exchanger.
    - UTAC also assumed that the SCR inlet temperature should be raised to 800^{o}F instead of the 650^{o}F CCM default or 730^{o}F optimum temperature; these assumptions raised natural gas use and costs unnecessarily.
    - UTAC's assumptions resulted in a more than three-fold increase in natural gas use compared to NPS estimates.
    - The resulting higher natural gas requirement led to UTAC estimates for heat input rate = 2,197 mmBtu/hr for Line 1 and 4,555 mmBtu/hr for Line 2. SCR capital costs for natural gas-fired industrial applications are directly proportional to the heat input rate. As a result of UTAC's overestimates for this parameter, its capital costs are overestimated by an additional 5–7 times.
- Inlet NO_x Emissions (NO_{xin}) to SCR:
    - NPS assumed that the duct burner would emit NO_x @ 0.1 lb/mmBtu based upon Alternative Control Techniques Document—NO Emissions from Stationary Gas Turbines, U. S. EPA 1/1/1993. The duct burner NO_x emissions were added to the induration furnace NO_x emissions and divided by sums of their heat inputs to estimate the uncontrolled NO_x emission rate = 1.20 lb/mmBtu for Line 1 and 0.91 lb/mmBtu for Line 2.
    - UTAC estimated uncontrolled NO_x emission rate = 0.16 lb/mmBtu for Line 1 and 0.11 lb/mmBtu for Line 2.
- Estimated actual annual fuel consumption?
    - NPS adjusted the heat input to yield the uncontrolled NO_x emissions estimated as described above.
    - UTAC appears to have used a similar method to estimate the same annual uncontrolled NO_x emissions.

Reheat costs were estimated as follows:

- CCM Table 2.10: Capital Cost Factors for Thermal and Catalytic oxidizers with Eqn. 2.34
- CCM Table 2.12: Annual Costs for Thermal and Catalytic oxidizers assumed a 19.0" H_2O pressure drop across the heat exchanger per CCM Table 2.13. This added $0.8 million and $1.8 million in annual electricity costs to Lines 1 and 2, respectively.

The table below shows the cost elements of adding SCR with reheat to each line.

Table 18. NPS estimated SCR + Reheat costs for UTAC Line 1 & 2 compared to UTAC estimates

SCR + Reheat	UTAC Line 1		UTAC Line 2	
	NPS	UTAC	NPS	UTAC
Capacity (mmBtu/hr)	300	2,197	622	4,455
Retrofit factor	1.5	1.6	1.5	1.6
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$12,064,772	$43,637,895	$18,600,939	$72,550,865
Interest rate (%)	3.50	5.5	3.50	5.5
Control Equipment Life (yr)	20	20	20	20
Capital Recovery Cost	$849,286	$3,652,470	$1,309,418	$5,500,301
Reheat Indirect Annual Cost	$262,785	$90,349	310,139	$106,540
Indirect Cost/Fixed O&M	$980,974	$3,772,408	$1,463,167	$6,182,554
Reheat Direct Annual Cost	$4,678,480	$15,468,890	$10,738,805	$31,434,467
Catalyst Life (hr)	16,000	8,000	16,000	8,000
Catalyst Replacement Cost	$85,076	$763,512	$163,129	$1,523,872
Direct Cost/Variable O&M	$5,398,834	$17,578,490	$11,847,347	$35,153,534
Total Annual Cost	$6,379,808	$21,350,897	$13,310,515	$41,336,088
Uncontrolled NO_x Emissions (Tons/yr)	1324	1325	1876	1874
Uncontrolled NO_x Emission Rate (lb/mmBtu)	1.83	0.16	1.22	0.11
NO_x Removal Efficiency (%)	80	50	80	50
Controlled NO_x Emission Rate (lb/mmBtu)	0.24	0.08	0.18	0.06
Net Tons Removed	1,052	663	1484	937
Cost-Effectiveness	$6,065	$32,228	$8,967	$44,115

A major factor in the difference between NPS estimates and those provided by UTAC is the addition of a 70% efficient heat exchanger to reduce natural gas consumption. This relatively small additional capital investment (Reheat Indirect Annual Cost) dramatically reduces natural gas consumption (Reheat Direct Annual Cost) and the capital cost of the SCR. The lower capital recovery cost and the lower operating costs result in much lower annual operating costs. Coupled with higher SCR control efficiency, the result is cost-effectiveness of $6,000/ton for SCR on Line 1 and $9,000/ton on Line 2. SCR on Line 1 is cost-effective when compared to MPCA's $7,600/ton acceptance threshold, while SCR on Line 2 is cost-effective when compared to the acceptance thresholds set by CO, NV, and OR.

Statutory Factor 2: Time Necessary for Compliance

According to UTAC, a state SIP revision is needed to approve a new statistically derived emissions limit methodology based on the emission performance of the new system, e.g. 99 percent UPL. Barr assumes that the revisions would occur within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023). After the SIP is promulgated, the technology would require significant resources and a time period of approximately five years to engineer, permit, and install the equipment.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

The CCM recommends a useful life of 20–25 years for SCR on industrial boilers.

6.2.4 SO_2 Four-factor Analysis

Control Selection & Efficiency

EPA's February 2013 BART determinations are now out-of-date and should be revisited for PM and SO_2 in addition to NO_x. UTAQ included analyses of strategies to reduce SO_2 emissions from Line 2:

Dry Sorbent Injection (DSI) – With New PM Control

While DSI has not been demonstrated at an operating taconite indurating furnace, DSI could conceptually be utilized if UTAC were to replace its existing PM controls (wet scrubbers) with controls that are compatible with DSI (e.g., baghouse or electrostatic precipitator (ESP)). Indurating furnace waste gas streams are high in water content and are exhausted at or near dew points. Gases leaving the indurating furnace are currently treated for removal of particulate matter using a wet scrubber. The exhaust temperature is typically in the range of 100^{o}F to 150^{o}F and is saturated with water. For comparison, a utility boiler exhaust operates at 350^{o}F or higher and is not saturated with water. The indurating furnace waste gas conditions following the existing wet scrubber would plug both the filters and the dust removal system. Therefore, the proposed control train would need to replace the existing wet scrubber with DSI and new PM control. With the removal of the existing wet scrubber and addition of new PM control after the DSI, the DSI control technology is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

The DSI evaluation conclusions vary in past SO_2 control equipment evaluations (2006 BART, 2010 Keetac BACT, 2011 Essar BACT reports, and 2012 EPA BART Determination). The 2006 BART reports and 2012 EPA BART Determination evaluated DSI after the existing scrubbers and concluded that the technology was not technically feasible due to high moisture flue gas resulting in caking and blinding of the associated filter bags. The 2010 Keetac BACT and 2011 Essar BACT reports concluded that DSI was technically feasible but concluded that a GSA was BACT with a baghouse for PM control.

Spray Dry Absorption (SDA) – With New PM Control

While an SDA has not been demonstrated at an operating taconite indurating furnace, an SDA could conceptually be utilized if UTAC were to replaces its existing PM controls (wet scrubbers) with controls that are compatible with an SDA (e.g., baghouse or ESP). Similar to the DSI control option, the moisture in the exhaust stream after the existing wet scrubber would plug the dust collection system. Due to the saturated waste gas exhaust, the proposed SDA control technology would require replacement of the wet scrubber with an ESP ahead of the SDA with baghouse control. Therefore, SDA with new PM control is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

The SDA evaluation conclusions vary in past SO_2 control equipment evaluations (2006 BART, 2010 Keetac BACT, 2011 Essar BACT reports, and 2012 EPA BART Determination). All of the facilities' 2006 BART reports (except Northshore Mining Company (NSM) due to NSM already employing wet ESP control technology) and the 2012 EPA BART Determination concluded that SDA was not technically feasible due to the high moisture flue gas. NSM's 2006 BART reports concluded that SDA was not cost-effective on a $/ton removed basis. The 2010 Keetac BACT report concluded that SDA was technically feasible but stated that GSA was BACT with a baghouse for PM control. The 2011 Essar BACT report concluded that SDA was not cost-effective on a $/ton removed basis.

Gas Suspension Absorption (GSA) – With New PM Control

While GSA has not been demonstrated at an operating taconite indurating furnace, there are not strong technical reasons prohibiting the installation and operation at an indurating furnace if alternative PM controls are used instead of wet scrubbers (e.g., baghouse or ESP). Similar to the DSI and SDA control options, the moisture in the exhaust stream would plug the dust collection system. Due to the saturated waste gas exhaust following the wet scrubber, the proposed GSA control technology would require replacement of the wet scrubber with an ESP ahead of the GSA with baghouse control. Therefore, GSA with new PM control is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

GSA was not assessed in the 2006 BART report. The 2010 Keetac BACT report concluded that GSA was technically feasible with a baghouse and was BACT. The 2011 Essar BACT report concluded that GSA was not cost-effective on a $/ton removed basis. There was an attempted application of GSA at a taconite pelletizing facility in 2018 in Indiana. The facility experienced severe operational issues with the GSA that resulted in an enforcement action for non-compliance, further supporting the uncertainty of the application of GSA on taconite indurating furnace. Regardless, UTAC proceeded to evaluate the control costs of a GSA for the purpose of this analysis.

Statutory Factor 1: Cost of Compliance

According to UTAC: The cost-effectiveness analysis compares the annualized cost of the emission control measure per ton of pollutant removed and is evaluated on a dollar per ton basis using the annual cost (annualized capital cost plus annual operating costs) divided by the annual emissions reduction (tons) achieved by the control device. For purposes of this screening evaluation consistent with the typical approach described in the EPA Control Cost Manual, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5 percent interest is assumed in annualizing capital costs. The resulting cost-effectiveness calculations are summarized in UTAC Table 6-2.

Table 19. UTAC Table 6-2: SO_2 Control Cost Summary, Line 2 Indurating Furnace

Additional Emission Control Measure	Installed Capital Cost ($MM)	Annual Operating Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost-effectiveness ($/ton)
DSI with New PM Control	$50,466,157	$10,090,749	108.2	$93,300
SDA with New PM Control	$120,947,748	$19,573,967	108.2	$180,891
GSA with New PM Control	$113,793,152	$18,757,651	108.2	$173,347

NPS review finds several areas in which the UTAC cost analyses deviates from CCM recommended methods:

- 5.5% interest rate instead of 3.5% used by MPCA in other analyses.
- 20-year life instead of 30 years recommended by the CCM
- 50% SO_2 control efficiency instead of 95% for SDA (CCM) or GSA

Statutory Factor 2: Time Necessary for Compliance

According to UTAC: A state SIP revision is needed to approve a new statistically derived emissions limit methodology based on the emission performance of the new system, e.g. 99 percent UPL. Barr assumes that the revisions would occur within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023). After the SIP is promulgated, the technology would require significant resources and a time period of approximately five years to engineer, permit, and install the equipment.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage and costs associated with solid waste handling and disposal are most appropriately accounted for in the Cost of Compliance analysis.

Statutory Factor 4: Remaining Useful Life

The CCM recommends 30 years for scrubber life.

6.2.5 PM Four Factor Analysis

Particulate emission reductions were not considered.

UTAC states that the existing wet scrubbers are 94% effective at reducing PM. NPS calculations based upon Appendix B of UTAC's four factor estimate that Line 1 PM emissions are almost 1,500 tpy and Line 2 PM emissions exceed 3,400 tpy. (MPCA indicates that Line 2 emitted 94 tons of $PM_{2.5}$ in 2017.)

According to the CCM, modern fabric filter baghouses and ESPs can remove at least 99.9% of particulate matter. Compared to the existing PM controls, a new baghouse or ESP could reduce annual PM emissions from Line 1 by 1,472 tons and Line 2 by 3,347 tons.

Integrated Multi-Pollutant Strategy

UTAC evaluated replacing the existing wet scrubber on Line 2 with a modern SO_2 scrubber and fabric filter or ESP. Although tail-end SCR with reheat may be technically-feasible when installed after the existing wet scrubbers, an integrated approach that precedes it with dry scrubbing and a fabric filter would minimize catalyst fouling (improving the technical feasibility of SCR) while drastically reducing PM emissions as well as reducing SO_2 emissions. The table below illustrates how such an integrated approach could reduce visibility-impairing emissions by thousands of tons per year in a cost-effective manner.

Table 20. NPS control cost estimates for an integrated approach to UTAC emissions

UTAC Fairlane Plant	Line 1	Line 2
Total Annual Cost (GSA+ESP+FF+SCR)	?	$ 28,783,891
Tons NO_x Removed	1,052	1,484
Tons PM removed	1,472	3,347
Tons SO_2 Removed	16	145
Total Tons Removed	2,540	4,976
Cost-Effectiveness ($/ton)	?	$ 5,785

MPCA RESPONSE TO NPS FEEDBACK

> *MPCA appreciates the suggestion to consider potential emission reduction measures from a multi-pollutant perspective. MPCA believes that is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts.*

6.2.6 NPS Conclusions and Recommendations United Taconite LLC–Fairlane Plant

NPS review finds that NO_x, SO_2, and PM emissions from UTAC's Lines #1 & #2 are not effectively-controlled. For example, tail-end SCR could reduce NO_x emissions by over 2,500 tons/yr for $6,000–$9,000/ton. MPCA should require SCR on UTAC lines #1 & #2.

An integrated approach to Line 2 emissions could yield combined emission reductions of almost 5,000 tons/yr at a cost of $29 million/yr for a cost-effectiveness value of $5,800/ton.

The NPS recommends that MPCA explore this opportunity to substantively address the haze-causing emissions from UTAC and other taconite facilities in Minnesota through the regional haze process.

Minnesota Land and Manoomin Protection Project Fellowship Team with Public Lab

On behalf of the Minnesota Land and Manoomin Protection Project Fellowship Team with Public Lab, we submit this comment on the Regional Haze State Implementation Plan.

The State of Minnesota celebrates its progress towards reducing nitrogen oxide and sulfur dioxide emissions, both of which form particulates and contribute to haze. We celebrate this success along with the State of Minnesota, while also looking towards a future where Minnesota can further decrease air pollutants.

Air pollution is unique amongst environmental pollutants because it travels so easily�that is, pollution in one place rarely stays there. The Plan shows that pollution in Voyageurs and Boundary Waters mostly comes from Minnesota. While other states also contribute to air pollution near Voyageurs and Boundary Waters, Minnesota is the biggest source. Therefore, reducing air pollution within Minnesota will make the biggest difference to meet the goals set forth in the Plan.

The State of Minnesota will not be able to meet emissions reduction targets in any part of the state while continuing to permit destructive, polluting industries in other parts of the state. Even though existing polluters continuously update their technology to reduce emissions, never allowing an industry to establish itself in the first place is the biggest reducer of air pollutants.

If permitted and built, the Huber Frontier Project (Huber Project) is likely to contribute to air pollution within the State of Minnesota, which likely would travel to Voyageurs and Boundary Waters. The Huber Project would be located in Cohasset, MN. The Huber Project is an OSB factory, which would emit from the combustion process. In its Environmental Assessment Worksheet (EAW), Huber explains that the OSB factory would emit particulate matter, nitrogen oxides, sulfur dioxide, volatile organic compounds, carbon monoxide, carbon dioxide, methane, nitrous oxide, lead, dust, odors, and various hazardous air pollutants, while also requiring increased vehicle traffic. Increased vehicle traffic will emit particulates, carbon monoxide, hydrocarbons, nitrogen oxides, and greenhouse gasses. For the drying process, the Huber Factory would require methanol and formaldehyde, both of which are toxic. See Huber EAW at pages 33 to 36.

Voyageurs and Boundary Waters are within 300 km of the Huber Project project site. While the EAW determined that the factory will have no adverse impacts on visibility in these areas, the Huber Factory only conducted a preliminary evaluation. Because of this, we do not agree with the EAW's conclusion that the Huber Project would not adversely impact Voyageurs and Boundary Waters. The preliminary assessment only considered a few of the numerous pollutants the Huber Project will emit. Additionally, air pollution is cumulative. Even if the Huber Project on its own minimally contributed to air pollution within Minnesota, the Huber Project is not the only polluter. We would also like to emphasize that the assessment in the EAW was prepared by the polluter themself, which requires us to take the assessment with a grain of salt.

Likewise, if the state permits and allows the building of the Talon-Rio Tinto Mine, a proposed Nickel mine near Tamarack, MN, the mine is very likely to hurt air quality in the State of Minnesota. This air pollution would likely impact Voyageurs and Boundary Waters. The Mine has not submitted an EAW to the State of Minnesota yet, so the project's specific impacts are unclear. While Talon states that this nickel mine would be the most environmentally friendly nickel mine to date, this does not mean much. Nickel mines are notorious polluters. Nickel mining releases greenhouse gasses, toxic aerosols, and drives deforestation to make way for mining. Nickel mining, smelting, and transportation all create dust.

The Eagle Mine in Michigan is comparable to the proposed Talon Mine. In a 2020 report, the Eagle Mine stated the facility emits dust while moving and storing ore. Also, the vehicles used in mining, moving, and storing ore produce emissions. Importantly, the report does not quantify emissions.

While air pollution is concerning because of its impact on the environment, air pollution also harms people. While the Plan focuses on Voyageurs and Boundary Waters as natural places, both areas are on Anishinaabe land. To this day, the Anishinaabe people (referred to as Chippewa in the treaties) retain usufructuary rights in Boundary Waters and Voyageurs. If they are built, air pollution from the Huber Factory and the Talon Mine will hurt the resources the Anishinaabe people have treaty rights to. In the meantime, other polluters continue to emit harmful substances that negatively impact the resources the Anishinaabe people rely on, such as wild rice (manoomin). Treaty-guaranteed resources, such as wild rice, game, and fish, are essential to the survival of the Anishinaabe people. These resources provide their daily sustenance and economic opportunities and are culturally important. Harm to these resources is detrimental to the survival of the Anishinaabe people.

A Nickel-Copper mine in Russia near the Norwegian border emitted nickel, copper, cobalt, sulfur dioxide, and dust. The mine also emitted toxic metals, including arsenic, lead, cadmium, and mercury. In a study near the mine, across the border into Norway and Finland, researchers found toxic metals concentrated in mushrooms, fish, game, and berries. While this is just one example, it is illustrative of the impact a mine can have on local resources. The State of Minnesota should not permit polluters that will likely emit toxic metals and substances that can concentrate in the environment. Potentially, toxic substances in the air could concentrate in the environment in Minnesota. In particular, the land that makes up Voyageurs and Boundary Waters contain treaty-guaranteed resources, such as wild rice, fish, game, and more. Particularly considering the importance of treaty-guaranteed rights (reinforced by the U.S. Supreme Court in 1999 in the Mille Lacs case (holding that Native Americans still hold treaty guaranteed usufructuary rights despite several events that could have extinguished the rights)), Minnesota must improve their air quality. These pollutants hurt the air, the people breathing the air, and have the potential to concentrate in the environment. Not allowing new polluters to enter the state, regardless of the jobs they promise, is key to preventing air quality degradation. Instead, the State of Minnesota has an opportunity to create long-lasting jobs and a thriving economy through community-led renewable energy initiatives that sustains the environment and people.

The updated plan calls for creating non-binding targets. While creating targets at all is an important first step, creating non-binding targets means the State of Minnesota cannot enforce the targets. Therefore, the State should include binding targets in its plan, which would require the Minnesota Legislature enact legislation to comply with the federally mandated haze plan. This way, Minnesota can set targets that are enforceable against both public and private entities. See Regional Haze SIP at 132.

For all the reasons detailed above, our team suggests the Regional Haze SIP focuses on preventing new pollution from entering the region in addition to reducing pollution from existing sources. While meeting the goals of the SIP is crucial, so is protecting the environment, treaty-guaranteed usufructuary rights, and humans from the harm of air pollution.

Sources:
Huber EAW: https://www.cohasset-mn.com/vertical/sites/{4DED3294-59E1-4C4A-B675-C7E6970BA170}/uploads/Frontier_Project_HEW_EAW_Final_2022.pdf

Iris Crawford, Will mining the resources needed for clean energy cause problems for the environment?, Massachusetts Institute of Technology (July 21, 2022) https://climate.mit.edu/ask-mit/will-mining-resources-needed-clean-energy-cause-problems-environment

Martine D. Hansen, et al., The Impact of a Nickel-Copper Smelter on Concentrations of Toxic Elements in Local Wild Food from the Norwegian, Finnish, and Russian Border Regions, International Journal of Environmental Research and Public Health (July 2017) https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5551132/

Eagle Mine 2020 Annual Mining and Reclamation Report (March 15, 2021)
https://www.michigan.gov/-/media/Project/Websites/egle/Documents/Reports/OGMD/2020-ogmd-eagle-mine-annual-report.PDF?rev=64f826ec726f4db0ab04cc83ab28ecd0

Southern Minnesota Beet Sugar Cooperative

SMBSC appreciates the opportunity to comment on MPCA's Regional Haze draft State Implementation Plan (RHSIP). Please see the attached document that details SMSBC's position on the draft RHSIP.

Southern Minnesota Beet Sugar Cooperative
83550 County Road 21, Renville, Minnesota 56284

October 7, 2022

Submitted Via Online Public Comment Form

Minnesota Pollution Control Agency
c/o Maggie Wenger
520 Lafayette Road N
St. Paul, MN 55155

Re: Comments Regarding Minnesota's Draft Regional Haze State Implementation Plan

Southern Minnesota Beet Sugar Cooperative (SMBSC) appreciates the opportunity to submit comments to the Minnesota Pollution Control Agency (MPCA) regarding Minnesota's Draft Regional Haze State Implementation Plan (RHSIP). The enclosed comments provide a detailed overview of SMBSC's position regarding the draft RHSIP.

We appreciate your efforts in thoughtful consideration of SMBSC's position and welcome the opportunity to have additional discussions towards a mutually agreeable path forward for how SMBSC is considered in the RHSIP. Should you have any questions or comments regarding this submittal, please contact me by phone at 320-329-4174 or via email at sagar@smbsc.com.

Sincerely,

Sagar Sunkavalli
Manager of Environmental Affairs

cc: Margaret McCourtney, MPCA
Hassan Bouchareb, MPCA
Kari Palmer, MPCA

BARR

Comments Regarding Minnesota's Draft Regional Haze State Implementation Plan

October 2022

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Comments Regarding Minnesota's Draft Regional Haze State Implementation Plan

October 2022

Contents

Barr Engineering Co. ("Barr") has developed the following comments on behalf of Southern Minnesota Beet Sugar Cooperative (SMBSC) regarding Minnesota's draft Regional Haze State Implementation Plan (RHSIP), based on review of the draft RHSIP and its supporting technical documentation.

Brief Procedural History

As part of development of the second implementation phase for the RHSIP SMBSC was required to submit a Regional Haze Four-Factor Analysis (FFA) on July 31, 2020 for Boiler No. 1 (Boiler 1, EQUI 17). The Minnesota Pollution Control Agency (MPCA), Federal Land Managers (FLMs), and the U.S. Environmental Protection Agency (EPA) provided initial comments on SMBSC's FFA. SMBSC provided responses to these comments on July 23, 2021. On January 18th, 2022, the MPCA met with SMBSC to inform decisions regarding what emission reductions are necessary to make reasonable progress toward attaining regional haze visibility objectives. During the meeting, MPCA informed SMBSC that they are recommending the installation of selective non-catalytic reduction (SNCR) controls on Boiler 1, by virtue MPCA determining that SNCR is "cost effective." SMBSC and MPCA met again on February 14th, 2022 where SMBSC stated its disagreement with MPCA's recommendation. Although SMBSC responded to MPCA's initial request in 2020 with a complete FFA, SMBSC explained that it did not believe additional control measures for NO_X and/or SO_2 are cost effective when all considerations are taken into account, not just the cost per pollutant reduced. SMBSC provided an additional letter to the MPCA providing supporting information on March 14, 2022. MPCA provided a response to SMBSC's March 2022 letter on April 20, 2022. MPCA made limited edits to the RHSIP document, but has not changed the major findings or recommendations.

SMBSC appreciates the opportunity to discuss this topic with MPCA and provide this additional information. Upon review of the draft SIP and supporting documentation, SMBSC has several comments. Due to time constraints, SMBSC reserves the right to review supporting documentation in further detail to further bolster SMBSC's position.

I. MPCA's recommendation for SMBSC to install NO_X emission controls to make reasonable progress for regional haze improvement lacks technical basis and is arbitrary and capricious when all relevant factors are considered

A. Q/d Screening Considerations

For the second regional haze planning period, States focused on demonstrating there is reasonable progress being made towards natural visibility goals, and if additional efforts are warranted, used the FFA methodology as outlined by the EPA to select sources for additional emission reductions. At the outset, SMBSC should not have been selected by MPCA to conduct an FFA and thus evaluate potential control measures.

Initially, MPCA applied the Q/d analysis (a source's annual emissions in tons divided by the distance in kilometers between the source and the nearest Class I area) on an individual emission unit basis, using the top 80% of statewide stationary source emissions as a cutoff threshold, in the selection of the 13 facilities and specific emission units of interest at those facilities. This step used an effective Q/d threshold of 7. SMBSC did not quality for FFA analysis under this approach because SMBSC's Q/d for Boiler No. 1 is approximately 4.1.

In comments using "their own criteria", the FLMs contended that the Q/d analysis should be applied to the entire facility emissions and not an individual emissions source. The FLMs' criteria are not evident in the record. In addition, the FLMs provided a specific list of additional facilities they recommended for FFA review. This list included SMBSC. The record also does not disclose how the FLMs selected SMBSC for further analysis.

MPCA acceded to the FLMs' request, and selected an "effective" Q/d of 4.6 for source inclusion. This approach is problematic on several levels. First, inclusion of the full facility emissions in the calculation will greatly increase a facility's Q/d value, yet emissions can only be practically controlled on source-by-source basis. Essentially, the method is attributing facility-wide emissions to individual emission sources that *they are not emitting* because the MPCA only requested a FFA for Boiler 1 at SMBSC. Such source aggregation is legally problematic under *West Virginia v. EPA,* 142 S.Ct. 2587 (2022). Second, with the inclusion of higher emissions, MPCA also lowered the Q/d threshold making source selection more aggressive and out of character with neighboring states. For instance, WI used the Q/d information developed by the Lake Michigan Air Directors Consortium (LADCO) Workgroup to select emission units over a Q/d of 10 at three facilities for further analysis[1]. Minnesota should follow Wisconsin's selection criteria as the two neighboring states have stationary sources potentially contributing to the same Upper Midwest Class I areas. Third, the oddly selected Q/d threshold happens to coincide exactly with SMBSC's value. On its face this suggests a result-driven, arbitrary process. MPCA essentially admitted as much during the February 14, 2022 meeting with SMBSC, where MPCA stated that the reason MPCA deployed a Q/d to include SMBSC was to specifically ensure that SMBSC would be required to conduct a FFA analysis, out of a desire to further regulate SMBSC's coal-fired boiler. MPCA thus reverse-engineered the Q/d to produce a pre-determined result. The entire FLM-inspired revisions process was both scientifically and legally suspect.

As described in the guidance[2] on regional haze state implementation plans for the second implementation period, States may find some or all of the following techniques useful for examining source impacts for the second implementation period:

a. Emissions divided by distance (Q/d)

b. Trajectory analyses

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[1] Wisconsin Regional Haze State Implementation Plan Revision for the Second Implementation Period, July 2021 (AM_WiRound2HazeSIP_20210730.pdf (widen.net))

[2] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf?VersionId=QC2nPZHuAH1VYmm3EuhV9ABIGm5rQynb

c. Residence time analyses

d. Photochemical modeling (zero-out and/or source apportionment)

The above techniques are listed in order from the least complicated and least accurate (Q/d) to the most complicated and resource intensive (photochemical modeling). Each technique has advantages and disadvantages. In general, the simple techniques (Q/d) are easy to implement, but do not provide detailed information. The more sophisticated techniques provide detailed information on particulate matter (PM) and PM species impacts. States may use Q/d as a surrogate for source visibility impacts, along with a ***reasonably*** selected threshold for this metric. Q/d is a less reliable indicator of actual visibility impact because it does not consider transport directions and pathways, dispersion and photochemical processes, or the particular days that have the most anthropogenic impairment due to all sources. MPCA selected the ***easiest and least accurate*** (compared to the alternatives listed above) technique, Q/d, to develop a list of sources to conduct a four-factor analysis. That is not necessarily inherently invalid, but it raises the greatest concerns over adequacy and potential manipulation.

MPCA's low Q/d threshold (4.6) selection was particularly surprising given that visibility in Minnesota Class I areas is already below the uniform rate of progress (URP) "glide-path" and approaching natural visibility. Figure 1 demonstrates the visibility trends for the Boundary Waters Canoe Area Wilderness (BWCAW), Voyageurs National Park (Voyageurs), and Isle Royal National Park.

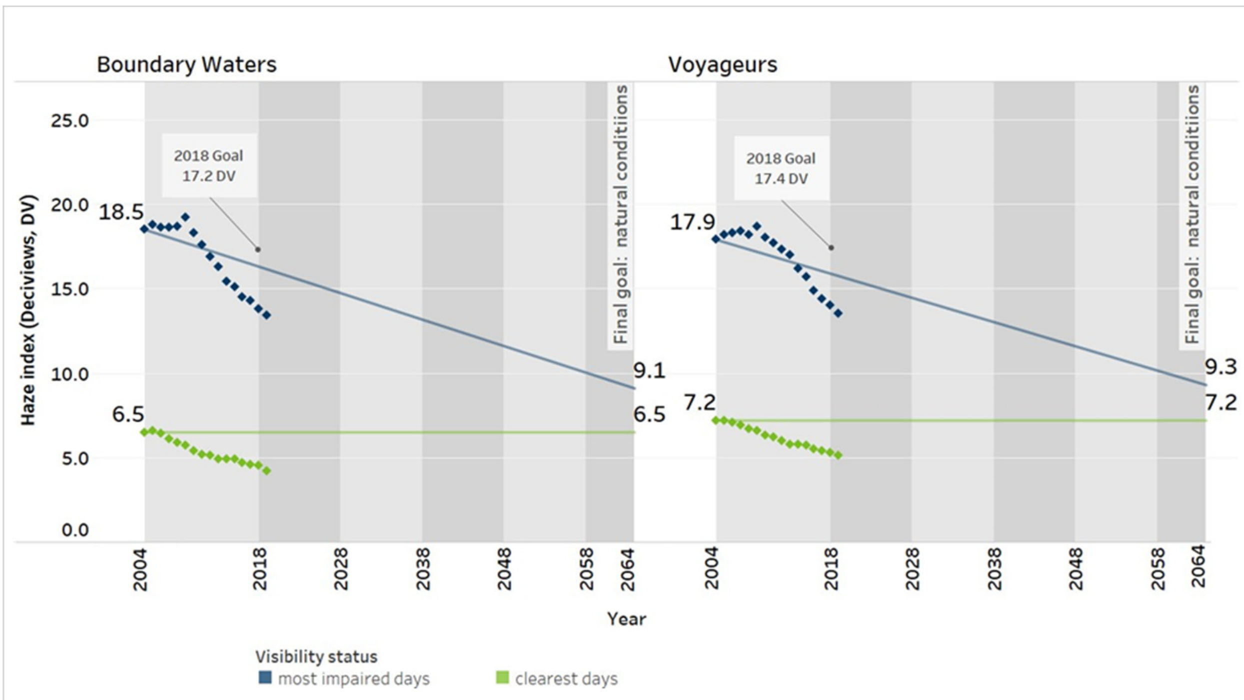

Figure 1 **Visibility Trend versus URP – Boundary Waters Canoe Area (BOWA1) and Voyageurs National Park (VOYA1)**

Notably, as part of Class I area Prevention of Significant Deterioration air permitting exercises, FLMs rarely evaluate permits at distances over 300 km and then only when sources are considerably larger than Boiler

1. Even then FLM-published guidance states that FLMs typically employ a Q/d of 10 to screen out sources from inclusion of visibility analysis on Class I areas[3]. The SMBSC example thus reveals a departure from normal practice on distance and emitter size, and a substantial departure on Q/d evaluation practices.

As a result of concerns about MPCA's methodology, and because the MPCA specifically invited permittees to prepare supplemental analyses to accompany the FFA, SMBSC prepared and included a trajectory analysis with the FFA, providing a more accurate picture of the relationship between SMBSC's emissions and conditions in the Upper Midwest Class I areas. The trajectory analysis showed that emissions from Boiler 1 are rarely if ever reach Upper Midwest Class I areas, let alone cause or impact visibility impairment.

B. MPCA lacks a technical basis to support that new NO_X emission controls at SMBSC are needed to make reasonable visibility progress

SMBSC provided a wind rose in correspondence with MPCA that the predominant wind directions near SMBSC are from the northwest and southeast/south-southeast, while all the Upper Midwest Class I Areas lie to the northeast. Refer to Figure 2 for details

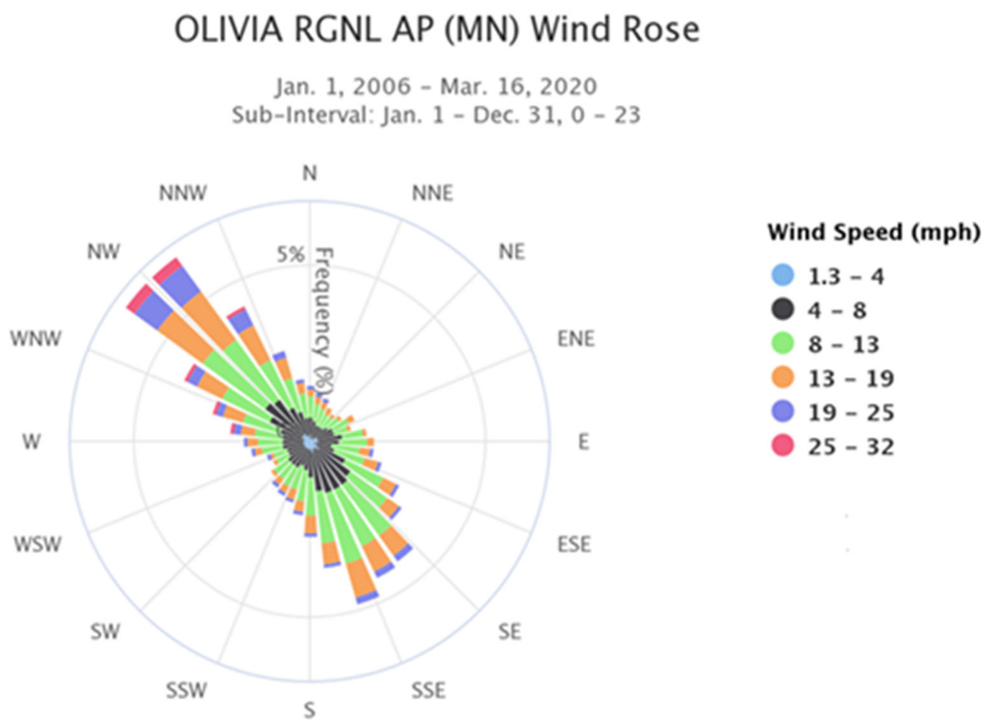

Figure 2 Olivia Wind Rose

[3]http://npshistory.com/publications/air-quality/flag-2010.pdf

The wind frequency from the southwest that is a precondition for transport SMBSC emissions to any of the Upper Midwest Class I areas is very rare (less than 1% of the time). This low frequency is compounded by SMBSC's 400-450 km distance to the nearest Upper Midwest Class I area. The distances alone are enough to eliminate SMBSC for consideration as part of any contribution analysis for the Upper Midwest Class I areas.

In addition, SMBSC included a forward-trajectory analysis with the original FFA submission, which is more accurate and sophisticated relative to MPCA's Q/d analysis for source inclusion. Refer to Figure 3.

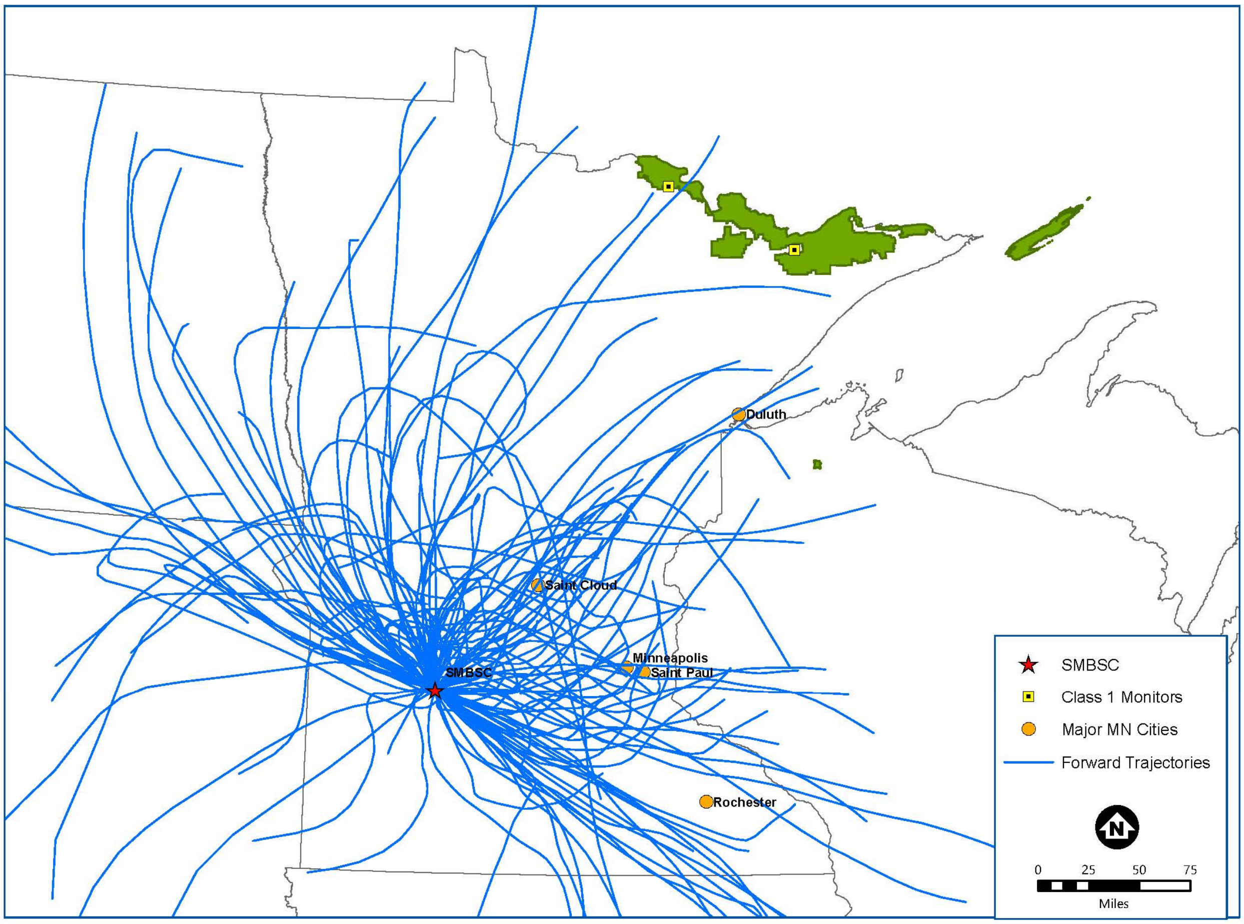

Figure 3 2018 Most Impaired Days Forward Trajectories

The analysis indicates that SMBSC's emissions seldom if ever reach the BWCAW and there is only a day or two each year the emissions even reach Voyageurs. Collectively, emissions from SMBSC only have the potential to reach Upper Midwest Class I areas in very rare circumstances, much less have ***<u>any</u>*** impact on visibility. By the time the emissions reach the Upper Midwest Class I areas, the emissions have undergone maximum dispersion and attenuation.

Therefore, SMBSC has contended that NO_X controls on a dollar per ton of pollutant removed basis are not cost-effective because the current evidence suggests there will be ***<u>negligible or no</u>*** visibility improvement resulting from the controls. This means that there should be no universal cost effectiveness ($7,600/ton per draft SIP) threshold applied equally to all facilities irrespective of distance to Upper Midwest Class I areas, wind directions, and trajectories provided by SMBSC to determine if NO_X controls are needed for reasonable progress. Further, while MPCA's cost threshold may be within the range of other state proposals, it is unnecessarily aggressive for a state with visibility conditions well below the uniform rate of progress glide path and is certainly on the higher end of other state proposals. Although SMBSC had not previously seen or taken a position on the MPCA's updated cost of NO_X controls set forth in the draft SIP, the principal disagreement is over whether they should be required in general. SMBSC has several comments on the MPCA's updated control costs and supporting documentation. However, based on a review of the draft SIP supporting documentation and recent pricing updates due to inflation, SMBSC recalculated the cost of SNCR and demonstrated that it is higher than $5,700/ton NO_X removed based on current pricing factors, which certainly should not be considered cost effective given the considerations in this section. Supporting documentation can be provided upon request. Additional detail on SMBSC control cost comments is provided in Section II.

Unfortunately, the MPCA states in the draft SIP that they did not consider visibility impacts to determine if NO_X and/or SO_2 controls would be required for reasonable progress. MPCA acknowledged that they would not complete modeling of proposed control measures to demonstrate reasonable progress would be made should the proposed control measures be installed. MPCA did not consider the trajectory analysis provided by SMBSC in its decisions. Further, the MPCA stated in a meeting with SMBSC that they ***would not consider the results of a full photochemical model demonstrating no or negligible impact*** to determine if NO_X and/or SO_2 controls would be required for reasonable progress, even though SMBSC offered to prepare such an analysis. The burden of proof then rests upon the agency to demonstrate that new controls are required to make reasonable progress. This is especially true because SMBSC conducted a more technically intensive analysis than MPCA that demonstrated no or negligible visibility impact on the Upper Midwest Class I areas. Therefore, MPCA's recommendation to install pollution new NO_X controls is unreasonable and lacks any technical basis for SMBSC to install pollution controls to make reasonable progress.

MPCA's decision to intentionally ignore visibility improvement at the Upper Midwest Class I areas to determine whether facilities should install controls is concerning. It is also logically inconsistent because MPCA is saying that visibility is not a consideration for the FFAs, but at the same time the MPCA is claiming that the pollution controls are needed to make reasonable (visibility) progress. Therefore, MPCA is in essence saying that visibility is not a factor for controls, but yet argues controls are needed to make a ***visibility*** improvement, with no technical demonstration that it is actually true. This is inconsistent and arbitrary.

The draft SIP contains many statements that further demonstrate that NO_X controls for SMBSC are unwarranted to achieve visibility objectives for the Second Implementation Period, even if SMBSC's emissions would actually reach the Class 1 areas:

- MPCA states: "Boundary Waters and Voyageurs *could reach adjusted goals before year 2064*… Between 2004 and 2009 there were measured increases in visibility impact at both Class I areas, but since 2009 the most impaired annual 5- year visibility impacts have declined per year an average 0.6 dv at Boundary Waters and an average 0.5 dv at Voyageurs. Should this trend continue, Boundary Waters and Voyageurs potentially could reach an adjusted endpoint by the third implementation period" and "Achieving natural conditions in 2064 looks promising even without adjusting for international impacts and wildland prescribed fires. Should those adjustments be made in future implementation periods, meeting natural conditions might begin to occur much earlier than 2064. While Minnesota does not seek U.S. EPA approval to make adjustments to adjust the 2064 end goal this implementation period, readily available information described in Section 2.1 (Step 1 – Ambient data analysis) suggests an earlier end point." Notably, MPCA's 2028 modeling does not even include all future emission reductions included in the long-term strategy (refer to Table 65 of the draft SIP) suggesting that visibility conditions will improve more than predicted. Therefore, MPCA has no basis to be recommending new NO_X controls for Boiler 1 when they don't appear to be needed to reach natural visibility conditions <u>and</u> where there is no technical basis to claim there will be any visibility improvement as a result of installing new NO_X controls on Boiler 1.

- The net effect following points clearly show that there is essentially no discernable potential to improve Upper Midwest Class I area visibility if SMBSC were to install new NO_X controls for Boiler 1. In essence the potential impact from the facility is a small fraction of several other small fractions, which clearly shows there is a diminishing return for visibility improvement.
    - Table 12 of the draft SIP shows that Minnesota only contributes 16.2% and 17.6% (for BWCAW and Voyageurs respectively) to visibility impairment.
    - Table 13 of the draft SIP shows that industry only contributes to 1.5% to the "Rest of Minnesota" visibility impairment.
    - SMBSC's emissions are a small fraction of the total emissions from the industry category in Table 13.
    - SMBSC's Q/d (emissions as it relates to distance) is insignificant compared to other sources and only accounts for a 0.74% and 0.77% percentile from BWCAW and Voyagers respectively. Refer to Table 29 and 30 of the draft SIP for details.
    - The wind frequency from the southwest that is a necessary precondition for transport SMBSC emissions to any of the Upper Midwest Class I areas is very rare (less than 1% of the time).
- MPCA states "Given that Minnesota is a major contributor to visibility impairment at its own Class I areas". This statement is misleading because Minnesota only accounts for a small percentage (16.2% and 17.6% for BWCAW and Voyageurs respectively) to visibility impairment, whereas there are many other contributors (including Canadian sources) that have a greater impact to Minnesota Class I areas.
- MPCA provided a brief summary of the proposed SIP strategies of other states in the "LADCO Regional Haze Workgroup." MPCA's draft SIP appear to be much more stringent and aggressive

compared to other LADCO states. Other sates primarily relied on previously planned emission reductions or changes to EGUs. MPCA is focusing unnecessarily on smaller industrial sources like SMBSC.

SMBSC recognizes that visibility improvement is the product of the aggregation of many reductions from many sources. SMBSC is not averse to considering controls where there appears to be real cost-effective benefits within an appropriate regulatory framework. SMBSC's objection lies in the fact that the draft RHSIP has been manipulated to recommend expensive controls specifically for SMBSC, without any visibility benefits.

C. There is substantial evidence of arbitrary targeting of SMBSC

SMBSC summarized several factors below that appear to be clear indications of arbitrary and capricious targeting by the MPCA and FLMs for SMBSC to install new NO_X controls:

- During meetings between SMBSC and MPCA staff, the MPCA emphasized fuel switching several times, which was not discussed in the FFA because it fundamentally changes the source and it is not economically viable for SMBSC. The only additional sources that MPCA sent FFA request letters to on February 14, 2020 were coal-fired sources. The MPCA's focus on fuels rather than visibility benefits is not consistent with the regulations or guidance. Further, SMBSC was not originally included in MPCA's list to complete FFAs.

- As described under item A. above, MPCA's change from an initial Q/d of 7 for individual emission sources to an "effective" Q/d of 4.6 for full facility emissions, precisely matching SMBSC's value. Especially where FLMs typically employ a Q/d of 10 to screen out sources from inclusion of visibility analysis on Class I areas[4], SMBSC appears to have been singled out and purposely selected due to FLMs specific interests.

- MPCA's admission that they will not consider a complete photochemical model to demonstrate no or negligible impacts at Upper Midwest Class I areas is concerning. This approach is the most technically and scientific intensive means to determine potential visibility improvement, and *SMBSC has offered to prepare such analysis*. The entire purpose of the regional haze rule is to improve visibility. Yet the MPCA will not even consider scientific methods to demonstrate pollution controls are needed to improve visibility, which is unreasonable especially when current evidence suggests there will be no meaningful impact on visibility. MPCA's opposition to consider improved scientific methods and analysis to demonstrate whether their proposed controls have any meaningful impact to visibility at the Upper Midwest Class 1 areas goes against the agency's commitment[5] that "its work is built on sound science" and "use dependable data to make reasonable decisions and drive the most effective environmental restoration and protection efforts." The regional haze rule per 40 CFR § 51.308(f)(2)(iv) requires

[4]https://www.fws.gov/guidance/sites/default/files/documents/FLAG%20Air%20Quality%20Phase%201%20report.pdf

[5] https://www.pca.state.mn.us/about-mpca/science-and-data

state to consider five factors to develop the long-term strategy. This includes consideration of the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. However, MPCA states in the draft SIP that they "did not consider the anticipated net effect on visibility due to emission changes expected in this implementation period. " Therefore, MPCA has failed to fulfill its regulatory obligations because MPCA did not complete the necessary modeling to demonstrate the impact on visibility with the proposed changes in the SIP including the recommendation for SMBSC to install NOx controls. Lack of resources to perform more sophisticated analysis **<u>is not a reasonable justification</u>**, given that the emitter has offered to conduct the analysis for agency review, and given the cost-of-controls at issue.

- As noted under item B. above per MPCA's admission in the SIP, Minnesota is already well on the way to achieving natural visibility at both the BWCAW and Voyageurs before 2064 with no changes to SMBSC emissions. If that is the case, the MPCA should not need new NO_X controls on SMBSC to make reasonable progress. Further, the 2028 modeling is overly conservative because it does not account for all planned emission reductions.

- MPCA states that visibility was not considered to determine if pollution controls were needed, but argues that pollution controls are needed to make a visibility improvement for reasonable progress with no technical demonstration that it is true. This is inconsistent, unreasonable, and arbitrary.

II. SMBSC Review of MPCA and NPS Control Cost Analyses and Comments

SMBSC conducted a detailed review of MPCA and NPS control cost comments and revisions. Specific details are included below:

- Universal comments applicable to all control cost analyses:
  - Interest rates – both the MPCA and NPS adjusted interest rates based on the current prime bank rate. For example, the MPCA used 3.5%. SMBSC provided comments in July 2021[6] explaining why using a historically low prime bank rate is not appropriate because interest rates fluctuate significantly over time. The current prime bank rate is 6.25% as of 10/4/2022. Therefore, MPCA and NPS revisions to SMBSC's interest rate are not appropriate, especially since financing for any future projects would not occur in 2022 if the compliance date Is 2028.
  - Reagent costs (e.g., fuel, water, urea, ash disposal, etc.) – the MPCA and NPS updated many of the reagent costs to default values from previous years with no adjustments for inflation. SMBSC assumed 3% inflation each year from the estimate year when current

[6] SMBSC. July 23, 2021. Responses to MPCA/EPA/FLM Four Factor Analysis Comments letter.

estimates were unavailable to estimate the time value of money. MPCA and NPS are incorrect to assume that historic pricing would continue to be representative of current day costs (e.g., 2017 costs do not reflect 2020 costs). In addition, rapid inflation in 2021 and 2022 have greatly increased prices for all sectors of the economy[7], further justifying adjustments made by SMBSC. NPS' assertion that outdated default cost estimates cannot be adjusted for inflation has no basis. MPCA and NPS should seek out updated figures for present day costs or provide realistic means of correcting for the time value of money to adjust reagent pricing for future control cost evaluations. In addition, NPS compared the inflationary scaling for reagents to the Chemical Engineering Plant Cost Index (CEPCI), which is used for equipment cost scaling, not reagents. This comment is incorrect.

- SMBSC disagrees with NPS that any controls are cost-effective for this implementation period especially when considering all factors presented in Section I.
- NPS commented that the CEPCI index used by SMBSC's consultant was too high. If anything, the index used by the consultant was too low. Costs have increased greatly since 2020 due to inflation. For example, the June 2022 CEPCI index was 832.6. MPCA should revise all cost estimates to reflect this change.
- Uncontrolled emission rates – SMBSC used the 2028 EPA modeling emission inventory for the basis of uncontrolled NO_X and SO_2 emissions (approximately 907 and 786 tpy respectively). MPCA made minor adjustments to these emission rates in their updated control costs (presumably as a result of NPS comments). While relatively inconsequential, SMBSC believes that the emission rates proposed in the FFA are reasonable representations of future actual emissions for 2028.
- SMBSC did not evaluate NPS wet FGD cost effectiveness calculations because the technology would increase sulfate and potentially mercury wastewater loading. Further, this is expected to generate a new wastewater stream requiring additional wastewater treatment and consuming significant amounts of energy. SMBSC reserves the right to evaluate the cost effectiveness of wet FGD at later time if required by MPCA or EPA. However, even the NPS cost calculations ($13,000/ton SO_2 removed) exceed MPCA's screening threshold of $10,000/ton for cost-effectiveness
- SMBSC's operating hours assumption (7,536 hr/yr) was based on the average Boiler 1 operating days for 2015 – 2019 (314 days/year). MPCA's value of 6,525 hours is too low and underestimates various costs particularly regarding labor and reagent use. In addition, it can misrepresent emission reductions from control devices. SMBSC's operating hours assumption is the appropriate value to use.

[7] https://www.bls.gov/news.release/cpi.nr0.htm

- SMBSC disagrees with all of NPS' comments regarding equipment life assumptions. SMBSC assumed a 20-year life for amortizing costs for all control technologies. SMBSC provided additional detail supporting this position in the July 2021[8] comment response letter to MPCA. While equipment may last longer than 20 years and there are examples of this in practice, SMBSC will not assume a "best-case" scenario to estimate costs that the facility may have to incur, especially when equipment life is not guaranteed. Further, NPS commented that operating time assumption of 314 days per year is considered a seasonal basis and could justify a longer equipment life. This is incorrect because 314 days per year represents 86% of a full year, which SMBSC does not consider to be seasonal because unit downtime is for routine maintenance. In addition, NPS quotes the EPA Control Cost Manual (CCM) section for SO_2 controls that states "Manufacturers reportedly design scrubbers to be as durable as boilers, which are generally designed to operate for more than 60 years"[9] to justify longer equipment life. This comment is baseless and SMBSC will not estimate life based on hearsay comments in the CCM.

- NPS stated "The vendor estimate relied on by SMBSC is not included in the SIP and the NPS cannot comment upon its usefulness. The cost methodology for estimates provided by SMBSC is of unknown origin." Capital cost estimates were provided by reputable vendors. Equipment quotes cannot be shared due to vendor confidentiality requirements and competitive advantage concerns.

- NPS stated "It appears that all values associated with operating costs are general (not specific to this site) and may be inflated. The NPS recommends that, SMBSC use established methods and present documentation to support a robust analysis." Refer to SMBSC comments above regarding reagent cost adjustment to account for inflation. Further, operating cost assumptions were provided in the calculations. In addition, SMBSC used established control cost calculation procedures per the CCM where appropriate with site-specific modifications as needed or applicable.

- SMBSC believes that the cost estimates provided by the facility to MPCA accurately represent costs that the facility may incur for both NO_X and SO_2 controls. SMBSC did not review NPS control cost estimates in detail, but reserves the right provide comments if requested in the future.

- NPS cost estimates used a retrofit factor of 1. SMBSC provided additional justification for the basis of the 1.5 retrofit factor in the July 2021[10] response to MPCA.

- Specific comments regarding SNCR and SCR NO_X controls

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[8] SMBSC. July 23, 2021. Responses to MPCA/EPA/FLM Four Factor Analysis Comments letter
[9] https://www.epa.gov/sites/default/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf
[10] SMBSC. July 23, 2021. Responses to MPCA/EPA/FLM Four Factor Analysis Comments letter

- MPCA changed the coal higher heating value (HHV) to 8,999 btu/lb from the original value of 9,152 btu/lb. This value is an input for the CCM cost estimation tool. It is not clear why the change was made since the original value was based off site-specific sampling from 2015-2019.

- MPCA adjusted the estimated annual fuel use parameter for SNCR and SCR per the CCM cost estimation tool. It is not clear why the change was made since the original value was based on the average of 2015-2019 actual fuel use.

- NPS states "MPCA assumed 49% efficiency by SNCR with an estimated Normalized Stoichiometric Ratio (NSR) = 1.57. NPS application of CCM Equation 1.17 yielded NSR = 0.94. As a result, NPS analyses project a 30% NO_X reduction (from CCM Figure 1.1c) down to 0.30 lb/MMBtu with much less reagent." MPCA's calculated NSR appears to be correctly applying equation 1.17 from the CCM. However, MPCA's calculations changed the inlet NO_X to 0.59 lb/MMBtu, but still assumed that the outlet concentration of 0.3 lb/MMBtu was achievable. SMBSC agrees that a 30% NO_X reduction suggested by the NPS more accurately represents the expected NO_X reduction. Incorporating this change, all the SMBSC cost comments in this letter, updating equipment costs with the most recent CEPCI (May 2022), and updating utility costs, the control costs for SNCR have increased above $5,700/ton. Coupling this with all comments included in this letter, SNCR is clearly not cost-effective and would be overly burdensome for the facility. SMBSC reserves the right to provide an updated cost estimate upon request.

- NPS commented specifically that SMBSC should use a retrofit factor of 1 for SNCR. SMBSC disagrees with this statement. The July 2021[11] comment letter from SMBSC to MPCA described in detail the retrofit considerations and expected difficulty that would apply to any control technology installation on Boiler 1 as mentioned above. NPS stated that they considered the July 2021[12] letter in their analysis, but it appears they disregarded SMBSC's explanation without a vendor cost estimate and reverted to the CCM default. SMBSC expects this to significantly underestimate costs. Further, SMBSC believes that Google earth photos support the facility's position that a retrofit of any pollution control technology would be very challenging and costly. Refer to the July 2021[13] letter for a detailed explanation. In addition, NPS is not familiar with facility operations and constraints, whereas SMBSC staff (and MPCA) are. Therefore, the NPS comment is not justified and should be rejected.

- NPS commented "SMBSC (and MPCA) has included costs to reheat the flue gas entering the SCR in addition to applying a 1.5 retrofit factor due to the difficulty of locating the SCR above the boiler exhaust. The SIP could be improved by a demonstration of why

[11] SMBSC. July 23, 2021. Responses to MPCA/EPA/FLM Four Factor Analysis Comments letter
[12] Id.
[13] Id.

both of these costs (retrofit factor =1.5 and reheat costs) are necessary." SMBSC already provided an explanation for the use of a reheat design for SCR in the July 2021[14] response to MPCA and provided justification for the retrofit factor as well. NPS even stated in their consultation comments (Appendix G of the draft SIP) that a 1.5 retrofit factor for SCR may be justified in their comments.

- NPS commented "Due to the high cost of natural gas, NPS analyses included a 70%-efficient heat exchanger in the reheat system and applied CCM methods to estimate operating parameters and costs. In estimating the capital and operating costs of SCR, the NPS included the duct burner heat input to size the SCR to handle the additional load." SMBSC's costs include the same heat exchanger design with a 70% heat recovery. NPS estimated a reheat heat input of 231 MMBtu/hr. SMBSC's calculated 26 MMBtu/hr for supplemental natural gas combustion. The NPS value is incorrect. SMBSC did not originally include the reheat firing in the SCR design. With this update combined with all other SMBSC comments in this letter, SCR control costs are above $11,000/ton.

- NPS commented "SMBSC selected "Method 2" to estimate catalyst replacement cost; this tends to produce higher cost estimates than "Method 1." 20,000 hours is an acceptable mid-range value for catalyst life for a high-dust configuration. However, SCR located following the ESP should have a longer catalyst life—NPS estimates 24,000 hours." SMBSC elected to use Method 2 for catalyst replacement costs. There is no requirement to use Method 1 for catalyst replacement. SMBSC is not going to assume "best-case" assumptions to estimate costs that the facility may reasonably incur with an SCR installation. Further, the catalyst operating assumption applies only to Method 1. Therefore, NPS' catalyst life comment is irrelevant.

- NPS commented "According to the CCM, "For other sources, the equipment life can be between 20 and 30 years." The CCM workbook assumes use of the 25-year mid-range value, which the NPS accepts as appropriate for a seasonal facility that only operates 314 days per year." SMBSC responded to this in previous comments and believes that a 20-year equipment life is appropriate.

- SO_2 control costs

  - Spray dry absorber (SDA) capital costs listed in the MPCA cost revisions improperly footnote the source of the estimate. Capital costs were based on a vendor estimate, not a former BART report from a separate facility.

[14] Id.

- NPS states that the dry sorbent injection (DSI) control efficiency with a baghouse should be 80-90%. SMBSC believes the estimated DSI control efficiency of 70% is a reasonable estimate and is even on the high end of the CCM DSI SO_2 control efficiencies (50-70%).[15]

- The 90% control efficiency applied for SDAs represents the mid-range of typical removal efficiencies and is a reasonable representation of what may be expected in practice.

- NPS states "MPCA and SMBSC could improve this analysis by explaining the rationale for requiring replacement of the existing electrostatic precipitator (ESP) with a new baghouse. This may be an unnecessary expense because the IPM DSI models include both ESPs and baghouses. Further, EPA's Clean Air Markets data for 2021 includes several coal-fired Electric Generating Units (EGUs) with DSI and ESPs" and that DSI can be added without a new baghouse with no existing emissions increase. The SDA/DSI designs were for a polishing baghouse. SMBSC was not planning to remove the existing ESP. In addition, SMBSC will not jeopardize compliance with existing limits to accommodate a new pollution control device with increased dust loading to the existing ESP without additional control. In addition, it is unlikely that there would be no particulate emissions increase with higher inlet ESP dust loading. As an example, if an ESP can capture 99% of the inlet particulate load, then a higher inlet load will also lead to a higher outlet loading. Further, it is unknow if the ESP can handle the increased dust loading without physical modification. SMBSC provided costs for a system that would be sized appropriately for this application that can guarantee no emissions increase, does not risk compliance or existing operations of the ESP, and provides consistent SO_2 control. These costs clearly show that SO2 controls are not cost effective.

- NPS provided ESP demolition costs and energy savings. However, the SDA/DSI designs were for a polishing baghouse installed downstream of the existing ESP. Therefore, the demolition and energy saving costs do not apply. SMBSC did not evaluate the validity of NPS cost savings estimates from demolition of the ESP, but reserves the right to evaluate and provide comments if requested at a later date.

- NPS states "NPS review finds that SMBSC and MPCA appear to have used an obsolete method to estimate costs of adding a Spray Dry Absorber (SDA). The current CCM SDA/CDS model includes a new baghouse in its cost estimates." SMBSC based costs off vendor quotes, which provide the purchased equipment cost. To estimate the total capital investment (TCI), SMBSC applied installation cost factors from the 6th edition of the CCM as a reasonable means to estimate these costs. The 7th edition cost procedures do not provide a means to estimate the TCI when only a purchased equipment cost is available. Therefore, the approach applied by SMBSC is a sufficient way of estimating these costs. NPS' comment is not valid unless they have documentation from EPA stating that the 6th

[15] https://www.epa.gov/sites/default/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf

edition procedures are incorrect. SMBSC holds that site-specific vendor estimates are more accurate and better representations of expected costs than EPA's CCM cost tool.

- NPS states "NPS analyses assumed that a new baghouse could be installed inside of the shell of the existing ESP or within its footprint and would not incur an extra retrofit penalty." The proposed SDA and DSI designs called for polishing baghouses, not a replacement of the existing ESP. Further, NPS has no basis to demonstrate that a replacement baghouse could be installed inside of the shell of the existing ESP or within its footprint. NPS cannot assume that this is a valid equipment design and that no extra retrofit penalty would occur. SMBSC disagrees with this statement and reserves the right to evaluate this further if requested.

CLIFFS

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October 7, 2022

Submitted Via Online Public Comment Form

Minnesota Pollution Control Agency
520 Lafayette Road N
St. Paul, MN 55155

Re: Comments Regarding Minnesota's Draft Regional Haze State Implementation Plan

To whom it may concern:

Cleveland-Cliffs Inc. (Cliffs) appreciates the opportunity to comment on Minnesota's draft State Implementation Plan (SIP) for Regional Haze and offers the following items for MPCA's consideration.

- Cliffs appreciates MPCA's increased focus on the role Canadian emissions have on visibility impacts in Minnesota's Class I airsheds which are directly adjacent to the Minnesota-Canadian border. MPCA's efforts to quantify these emissions are a significant improvement over the information that was available during the first implementation period. Section 2.2.3 of the draft SIP states, *"Emissions sources located outside the boundary of the modeling domain, from the direction of Canada, carry a very significant portion of the visibility impact at Boundary Waters (37.7%) and Voyageurs (40.2%). This is a much higher percentage than the first implementation period at Boundary Waters (11%) and Voyageurs (15%) as shown in Table 9 above. The portion of Canada within the modeling domain is significant contributor at Boundary Waters (7%) and Voyageurs (10%). … Broadly assuming all the impacting sources are in Canada, total impact estimates from Canada would be Boundary Waters 44.7% (37.7% plus 7.0%) and Voyageurs 50.2% (40.2% plus 10.0%) as shown in Table 12. However, that can't be determined without further study. Some of the contribution from outside the boundary could be from U.S. air traveling outside the boundary then re-entering."*

  While this information is an improvement from previous years' efforts, we encourage MPCA to continue efforts in future years to better quantify and model Ontario emission sources near the border rather than simply including a large block of general Canadian emissions. **We request that MPCA and LADCO work with Canada, and in particular, Ontario, so that future Regional Haze SIP revisions will include more accurate emission estimates and modeling in order to better quantify these international sources' impact on visibility.** Additional work is needed to better understand Canadian emissions from wood processing and paper manufacturing facilities; power generating facilities; and forest fires in close proximity to the Minnesota-

Canadian border. Specifically MPCA and LADCO should work with Ontario's Ministry of the Environment, Conservation and Parks to better understand emissions nearby sources including, but not limited to, Resolute Forest Product paper mills and other operations in Fort Frances, Atikokan, and Thunder Bay; Domtar's paper mill in Dryden; Birla's paper mill in Terrace Bay; and Ontario Power Generations' power plant in Atikokan.

- Cliffs appreciates MPCA's discussion on 2064 Endpoint Adjustments in Sections 2.1.6. but is disappointed that MPCA was unable to propose adjustments to the 2064 endpoint to more accurately account for uncontrollable emissions from international sources or prescribed wild fires as allowed by 40 CFR § 51.308(f)(1)(vi)(B). The Draft SIP notes, *"MPCA does not believe it has scientifically valid data and methods—this second implementation period—to estimate the impacts from human activity outside the United States and/or wildland prescribed fires to seek U.S. EPA approval to adjust the 2064 endpoint and the URP. Current measurements are well below the URP glidepath and have been steadily trending downward. While Minnesota does not seek U.S. EPA approval to make adjustments to the 2064 end point this implementation period, readily available information by other organizations suggests Boundary Waters and Voyageurs could reach adjusted goals before year 2064."*

  The Draft SIP notes that the current 2064 endpoint for Boundary Waters is 9.1 dv but when accounting for uncontrollable emissions the adjusted 2064 endpoint would be 11.6 - 12.1. Similarly, the current 2064 endpoint for Voyageurs is 9.3 dv but an adjusted 2064 endpoint would be 12.0 - 12.5. MPCA's data shows actual 2018 visibility conditions at 13.4 dv and 13.5 dv for Boundary Waters and Voyageur's, respectively. Adjustments to the 2064 endpoint are necessary to accurately account for uncontrollable emissions and establish achievable, appropriate targets. Not properly adjusting the endpoints may result in unnecessary, expensive, over control scenarios for Minnesota emission sources. **Accordingly, we request that MPCA refine its data and methods in the future so that the next Regional Haze decadal review can propose appropriate adjustments to the 2064 endpoint and interim implementation period goals.**

Sincerely,

Jason Aagenes

Jason Aagenes
Program Director – Environmental Permitting and Regulatory, Mining

Cc: Margaret McCourtney, MPCA
Hassan Bouchareb, MPCA
Kari Palmer, MPCA

United States Environmental Protection Agency, Region 5

Mr. Hassan Bouchareb,

Attached here, please find EPA Region 5's comments on the proposed Minnesota Regional Haze State Implementation Plan (SIP) Revision for the 2nd Implementation Period that was posted for public comment on August 22, 2022. Please note that our comments are designed to clarify and to help further ensure that the submittal will address the applicable Regional Haze Rule requirements. For those comments where we emphasize the need for additional justification or clarification, it is important to have a clear understanding of how decisions are reached. If you have any questions, please feel free to contact me, or Alisa Liu at liu.alisa@epa.gov.

Sincerely,

Pamela Blakley, Supervisor
Control Strategies Section
Air and Radiation Division
United States Environmental Protection Agency-Region 5
Blakley.Pamela@epa.gov

ATTACHMENT

US EPA Comments regarding the August 22, 2022 Draft for Public Comment of Minnesota's Regional Haze State Implementation Plan

On August 22, 2022, Minnesota Pollution Control Agency (MPCA) shared a link with USEPA Region 5 to draft revisions to Minnesota's Regional Haze State Implementation Plan (SIP) that was posted for a public comment. The public comment period concludes on October 7, 2022. USEPA provides these comments geared toward additional clarification to help further address the Regional Haze Rule requirements.

CHAPTER 1. REGIONAL HAZE PROGRAM OVERVIEW

Section 1.3 U.S. EPA's Regional Haze Federal Implementation Plan (FIP) for taconite facilities

1. **Page 6:** *"…U.S. EPA and the taconite facilities are currently working to resolve the disagreements through settlement discussions. If a settlement agreement is reached with the Minnesota taconite facilities named in the FIPs (Cleveland-Cliffs Minorca Mine, Hibbing Taconite Company, Northshore Mining Company, United Taconite - Fairlane Plant, U.S. Steel - Keetac, and U.S. Steel - Minntac), U.S. EPA must publish a Federal Register notice announcing the settlement agreement, initiate a public notice and comment period, and respond to any comments received."*

   Comment:
   Although the discussion above indicates U.S. EPA must "respond to any comments received," please note that U.S. EPA does not necessarily respond to comments on a settlement agreement.

   Additionally, please annotate the reference to U.S. Steel – Minntac in the parenthetical expression above to indicate a settlement agreement for Minntac was already reached, and a final rule revising the FIP for Minntac was finalized in 2021 although the final two sentences of the full paragraph, not excerpted here, also provide that information.

CHAPTER 2. REQUIRED REGIONAL HAZE SIP ELEMENTS

Section 2.2.3. States impacting Minnesota's Class I areas

2. Page 34: "*In Northeast Minnesota, the industry sector grouping is by far the most significant contributor to impairment at 4.7% of the region total at 6.5% at Boundary Waters and 7.3% at Voyageurs. The EGU sector contributes 1.3% of the region total at Voyageurs.*"

Comment:
Please clarify the percentages referenced in the statement above.

For the tables in Section 2.2.3 with columns labeled "Region contribution to visibility (%)" and "Contribution to visibility (%)," please consider adding "impairment" after "visibility" or referring to contribution of light extinction. For the tables with associated 2028 NO_x and SO_2 emissions used in the analysis, please clarify in the table headings if the column labeled "Annual emissions (tons)" is in reference to 2028 emissions.

3. Page 35-36: "*Northeast Minnesota contributes about 40% visibility impairment at both Boundary Waters and Voyageurs. With 60% of the visibility impairment from Minnesota attributed to the rest of the state…*" In Table 13 for Northeast Minnesota, the Region total for sector groups is listed as a 6.5% contribution to visibility at Boundary Waters and 7.3% at Voyageurs. For Rest of Minnesota, the Region total for sector groups is listed as a 9.7% contribution to visibility at Boundary Waters and 10.3% at Voyageurs.

Comment:
Please clarify what the various percentages are relative to in the references above as well as similar references throughout.

4. Page 36: "*In Minnesota, large reductions in NO_x emissions of around 66,200 tons from vehicles (on-road and off-road) were accounted for between 2016 and 2028.*"

Comment:
It would be helpful to mention to what the large reductions in NO_x emissions from on-road and off-road vehicles are attributed for Minnesota and the other states where this observation was presented.

5. Page 37, 38: "*North Dakota overall contributes mostly nitrate to visibility impairment at Boundary Waters (60%) and Voyageurs (53%)…Iowa overall contributes mostly nitrate to visibility impairment at Boundary Waters (60%) and Voyageurs (53%)…*"

Comment:

Please clarify if the percentages above, and in similar references for Nebraska, Wisconsin, Missouri, and Canada, are meant to compare the amount of sulfate to nitrate that comprise a region's total contribution to visibility impairment. For example, please clarify if Iowa's total contribution is made up of 60% nitrate and 40% sulfate, which together contribute 4.3% to the visibility impairment at Boundary Waters and 4.1% visibility impairment at Voyageurs as indicated in Table 17.

Section 2.3 Step 3 - Selection of sources for analysis

6. Page 45: *"…in alignment with other LADCO member states, the MPCA conducted a screening analysis for stationary sources to determine which sources would be selected. Ultimately, the MPCA selected sources that represent roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the screening analysis for Boundary Waters and Voyageurs."*

Page 82: *"MPCA selected sources for analysis that correspond to roughly the top 85% of stationary source emissions from Minnesota sources that may impact visibility based on the Q/d Analysis for both the Boundary Waters and Voyageurs Class I areas. Adding these four facilities resulted in an effective Q/d threshold of 4.6."*

Page 86: *"Minnesota settled on a Q/d threshold value of 4.7 in consultation with FLMs. This value also corresponds to roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the Q/d Analysis for both the Boundary Waters and Voyageurs Class I areas."*

Comment:
Two Q/d values are noted as a threshold: 4.6 and 4.7. Please clarify which threshold was intended.

In explaining that "MPCA selected sources for analysis that correspond to roughly the top 85%...", MPCA did not explicitly state that sources were selected based on Q/d. Selecting the top 85% of emissions from sources located generally throughout the state would not necessarily correlate with visibility impacts on Class I areas in the same way that Q/d would or in the other ways as addressed in the 2019 RH Guidance on page 13, such as trajectory analyses, residence time analyses, or photochemical modeling. As noted in the 2019 Regional Haze Guidance, states are expected to provide "a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures…" 2019 Regional Haze Guidance at 27. As such, it would be helpful to explain in Section 2.3 if a Q/d threshold of roughly 4.6 (p. ii, 82) or 4.7 (p. 86) was a consideration in arriving at the selection of sources, which also represents the top 85% of emissions.

Section 2.3.2 Estimating visibility impacts for source selection

7. **Page 48:** "*MPCA relied on the Q/d results created by the Lake Michigan Air Directors Consortium (LADCO) for industrial point sources using 2016 emissions inventory data with revisions made to account for certain facilities that were idled or operating at reduced capacity in 2016. [Footnote 75].*"

   Comment:
   Footnote 75 refers to Appendix C: LADCO Documentation; LADCO Regional Haze 2018-2028 Planning Period TSD. To provide background on the Q/d results created by LADCO that MPCA relied upon, please include in Appendix C LADCO's October 14, 2020, memo regarding "Description of the Sources and Methods Used to Support Q/d Analysis for the 2nd Regional Haze Planning Period." Although a weblink is provided in Appendix C, please provide the full memo.

8. **Page 52:** "*Table 29 below displays the facility location, emissions data (total emissions of NO_X, SO_2, PM2.5, NH3, and VOCs), distance, the associated Q/d value, percentile (percent of the total Q/d for the Class I area), and cumulative percentile for the Boundary Waters Class I area.*"

   Comment:
   It would be helpful to note for Table 29 and 30 if the percentile and cumulative percentile only reflect the listed facilities and not an overall percentile that would account for contributions by other sources, such as mobile, international or biogenic.

2.3.4 Option to consider the five required additional factors when selecting sources

9. **Page 58-59:** *"The MPCA made a specific modification in its modeling analysis to account for the Regional Haze Taconite FIP, discussed previously in Section 2.6.1…The expected emission changes due to the Regional Haze Taconite FIP are discussed in more detail in Section 2.3.5 below alongside other sources not selected for analysis due to already having effective emissions controls in place. These emission reductions are reflected in the 2028 modeling inventory."*

   Page 62: *Table 32. Summary of emission units with existing effective controls*

   Page 78-80: *"U.S. EPA only recently finalized the limits for this facility [U.S. Steel – Minntac]…"*

   Page 128: *"MPCA considers the taconite emissions projection fairly conservative, post-FIP controls resulting in lower emissions, for a few reasons…"*

   Page 134: "*Overall, MPCA believes the RPGs are a conservative estimate of the visibility improvements due to Minnesota's long-term strategy for the second regional haze* *implementation period. The modeling analysis, and therefore the RPGs, do not account for all the emission reductions expected from Minnesota's long-term strategy suggesting that visibility conditions will improve more than predicted."*

Comment:
Please provide some context in Table 32 and statements regarding the emission projections that acknowledges the settlement negotiations involving the taconite FIP, such as was done in Section 1.3, and discuss the relative sensitivity of MPCA's projections to potential changes.

Although discussed on pages 78-80, please further elaborate how the final rule revising the FIP pertaining to U.S. Steel - Minntac was considered or how it would impact MPCA's projections.

Section 2.3.5 Sources that have existing effective emission control technology

10. Page 61-80: MPCA provides five years of emissions data and projected 2028 emissions for each of the facilities listed. MPCA makes similar observations for each facility, noting, for example, *"…the facility has been implementing the controls described earlier resulting in a reasonably consistent emission rate over the most recent five years…MPCA has no reason to believe that emission rates for these emission units will increase in the future given the applicable limits, control equipment, and associated requirements are already enforceable requirements…"*

Comment:
While MPCA provides actual recent emissions and projections as support for not selecting sources for four-factor analyses, MPCA should further address whether the facilities need to hold emissions to a certain level for reasonable progress, and if those limits should be enforceable in the SIP. *See* Section 4.1 of the 2021 Clarifications Memo.

Section 2.4.2 Emissions information for characterizing emission-related factors

11. Page 94: "*Additional emission unit specific information utilized in the four-factor analyses, including permitted NO_x and SO_2 emission rates, actual NO_x and SO_2 emission rates, and the design heat input capacity of the emission units is provided in Table 49 below."*

Comment:
Table 49 shows variability between permitted rates and actual rates at sources selected for analysis. In expounding upon the information in Table 49, please indicate if the data in Table 49 combined with data elsewhere in the document demonstrates the facilities have been implementing their existing controls resulting in a reasonably consistent emission rate that is not expected to increase in the future. Based on the information, MPCA will need to explain why it is

reasonable to determine that existing controls at these facilities are not necessary for reasonable progress per Section 4.1 of the 2021 Clarifications Memo. If MPCA is not making this determination, it should consider analyzing existing controls at these facilities for potential upgrades or optimization. *See* 2021 Clarifications Memo at 9: "Information on a source's past performance using its existing measures may help to inform the expected future operation of that source. If either a source's implementation of its existing measures or the emission rate achieved using those measures has not been consistent in the past, it is not reasonable to assume that the source's emission rate will remain consistent and will not increase in the future."

Section 2.5.1 Cost of Compliance (statutory factor 1)

12. Page 112: Regarding Southern Minnesota Beet Sugar Cooperative. *"No additional information provided by the facility suggests that the NO_x controls are not cost-effective for the facility in this regional haze implementation period. The MPCA maintains that the NO_x controls are cost-effective and necessary to continue making reasonable progress, but the MPCA has not reached an agreed path forward with the facility to install the NO_x controls."*

Page 173: Table 82 regarding Southern Minnesota Beet Sugar Cooperative. *MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.*

Comment:
It would be helpful to mention on page 112 MPCA's decision on page 173 to consider reevaluating this facility as part of the 2025 progress report or the 2028 comprehensive update.

Section 2.5.8 Minnesota's Long-Term Strategy

13. Page 119: **"***All of the emission reduction strategies that will contribute to meeting the RPGs are documented in this SIP submittal. As discussed previously in Section 2.5.6, Minnesota considered several factors in developing its long-term strategy and has met the requirements of 40 CFR § 51.308(f)(2) as summarized below."*

Comment:
Page 120 lists the measures deemed necessary for reasonable progress that are a part of MPCA's long-term strategy. On page 112, regarding the Southern

Minnesota Beet Sugar Cooperative, MPCA notes the following: "No additional information provided by the facility suggests that the NO_x controls are not cost-effective for the facility in this regional haze implementation period. The MPCA maintains that the NO_x controls are cost-effective and necessary to continue making reasonable progress, but the MPCA has not reached an agreed path forward with the facility to install the NO_x controls."

These control costs vary from ~$2,900/ton to ~$3,800/ton. These costs are in line with what has been considered reasonable in the past by the Agency.

While MPCA states on page 112 "that the NO_x controls are cost-effective and necessary to continue to make reasonable progress," it is unclear whether these controls (and which of these controls) actually have been determined by MPCA to necessary for reasonable progress in the second planning period. MPCA has seemingly taken the position that cost-effective controls should be required at this facility, though the measure(s) are not included in the state's long-term strategy on page 120. In this regard, MPCA indicates on page 173 that it "will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update." MPCA should better clarify whether controls at this facility will be required and whether controls at this facility are part of the State's long-term strategy in the second planning period. See 51.308(f)(2). To the extent that MPCA has determined that particular measures are necessary, all such necessary measures are required to be federally enforceable and included in the SIP.

Section 2.6.2 Reasonable Progress Goals for Boundary Waters and Voyageurs

14. Page 132: "*The 2028 model projection for the clearest days, 4.5 dv for Boundary Waters and 5.3 dv for Voyageurs, ensures "no degradation" from baseline visibility, 6.5 dv for Boundary Waters and 7.2 dv for Voyageurs (see Section 2.7 for more details).*"

Comment:
Should the value of 6.5 dv noted above be 6.6 dv based on Table 64 "Reasonable progress goals (RPG) at Boundary Waters and Voyageurs" or should Table 64 be revised with a value of 6.5 dv?

15. Page 134: Regarding Table 65 Long term strategy measures reflected in the RPGs for Boundary Waters and Voyageurs, MPCA notes, *"Overall, MPCA believes the RPGs are a conservative estimate of the visibility improvements due to Minnesota's long-term strategy for the second regional haze implementation period. The modeling analysis, and therefore the RPGs, do not account for all the emission reductions expected from Minnesota's long-term strategy suggesting that visibility conditions will improve more than predicted."*

Comment:
MPCA included a similar statement in the TSD for the corresponding table, which is Table 24 in Appendix A on page 65:

"Overall, the MPCA believes the RPGs at Boundary Waters and Voyageurs appear to be somewhat conservative estimates of visibility improvements due to the long-term strategy for the second implementation period. Not all emission reduction measures could be reflected in the modeling, and some emissions increase projections reflected in the modeling are unlikely to occur."

It would be helpful for MPCA to include the same conclusion from Table 65 in the main document for the corresponding Table 24 in the TSD that was stated above: "…suggesting that visibility conditions will improve more than predicted."

Section 2.9.1. Consultation with states

16. Page 142-145: MPCA indicates that it "met" with representatives from specific states that it had identified as reasonably contributing to visibility impairment at Minnesota Class 1 areas. MPCA states that during the development of this SIP submittal, that it has "contacted" representatives from those states, "shared details" with them, "requested" information from them, and have been provided information in various forms in response.

Comment:
While MPCA provides detailed synopses of its interactions with the "reasonably contributing" states, Section 2.9 does not appear to explain how MPCA determined, and by what criteria, which states are "reasonably contributing." The submittal to EPA should explain how MPCA determined which states were reasonably contributing states for purposes of consultation.

MPCA also does not provide copies of the correspondence/contacts/requests/responses documenting the consultation. The documentation of the consultation should be provided in the submittal to EPA, e.g., as an Appendix. *See* 40 CFR 51.308(f)(2)(ii)(C) ("All substantive interstate consultations must be documented.")

NPCA

Attached comments submitted by the Coalition to Protect America's National Parks, Environmental Law & Policy Center, Minnesota Center for Environmental Advocacy, National Parks Conservation Association, and Sierra Club. We appreciate the opportunity to comment. Please feel free to contact us if you have any questions.

October 7, 2022

Submitted electronically via MPCA webpage

Minnesota Pollution Control Agency
c/o Maggie Wenger
520 Lafayette Road
St. Paul, Minnesota 55155

Re: Minnesota's Draft State Implementation Plan for Regional Haze Round II

Dear Ms. Wenger:

The Coalition to Protect America's National Parks, Environmental Law & Policy Center, Minnesota Center for Environmental Advocacy, National Parks Conservation Association, and Sierra Club submit these comments and attached report[1] regarding the Minnesota Pollution Control Agency's ("MPCA") Draft State Implementation Plan ("Draft SIP" or "proposed SIP") Update for Regional Haze. Minnesota's Draft SIP, as published on August 22, 2022, outlines the state's plan for pollution reduction during the second Regional Haze implementation period ("Round II").

The Coalition to Protect America's National Parks ("Coalition") is a non-profit organization composed of over 2,100 retired, former and current employees of the National Park Service (NPS). The Coalition studies, speaks, and acts for the preservation of America's National Park System. As a group, we collectively represent over 40,000 years of experience managing and protecting America's most precious and important natural, cultural, and historic resources.

Environmental Law & Policy Center ("ELPC") is a nonprofit organization that advocates and litigates to protect air and water quality and natural places throughout the Midwest and Great Lakes region. ELPC is headquartered in Chicago, and has regional offices and members throughout the Midwest, including an office in Minnesota. ELPC has long advocated for reducing emissions of

[1] Attached to the comments is "*Review and Comments on Reasonable Progress Controls for the Minnesota Regional Haze Plan for the Second Implementation Period*," which was prepared for NPCA and Sierra Club by Victoria R. Stamper (October 5, 2022) (Enclosure 1, "Stamper Report"). Ms. Stamper is an independent air quality consultant and engineer with extensive experience in the regional haze program.

air pollution that harms public health, exacerbates climate change, imperils the natural environment, and impairs recreational and aesthetic enjoyment of natural places.

Minnesota Center for Environmental Advocacy ("MCEA") is a nonprofit environmental organization that works in the courts, the legislature, and state agencies to protect Minnesota's environment, natural resources, and the health of its people.

National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's national parks for present and future generations. NPCA performs its work through advocacy and education, with its main office in Washington, D.C. and 24 regional and field offices. NPCA has over 1.7 million members and supporters nationwide, with more than 31,000 in Minnesota. NPCA is active nationwide in advocating for strong air quality requirements to protect our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, climate change and mercury impacts on parks, and emissions from individual power plants and other sources of pollution affecting national parks and communities. NPCA's members live near, work at, and recreate in all the national parks, including those directly affected by emissions from Minnesota's sources.

Sierra Club is a national nonprofit organization with sixty-seven chapters and more than 832,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. Sierra Club has long participated in Regional Haze rulemaking and litigation across the country in order to advocate for public health and our country's national parks.

As detailed below, Minnesota Pollution Control Agency's proposed SIP will not result in reasonable progress towards improving visibility at the Class I areas its sources impact. To satisfy the Clean Air Act ("Act" or "CAA") and Regional Haze Rule ("RHR"), MPCA must correct the flaws identified in these comments and in the attached technical report by Victoria Stamper before submittal to EPA, including:

- MPCA ignored recommendations from the Federal Land Managers ("FLMs");
- MPCA's Draft SIP unlawfully fails to conduct Four-Factor Analyses and include controls on the six taconite sources, which are generally among the highest Q/d values for the State's two Class I areas, erroneously relying on an "effectively controlled" argument;
- MPCA's Draft SIP unlawfully fails to include practically enforceable emission limitations, as required by the Clean Air Act;
- MPCA's Draft SIP unlawfully relied on an announced retirement and failed to consider whether cost-effective control measures could be implemented in the meantime;
- MPCA's Draft SIP unlawfully relies on unenforceable, recent emissions, which are lower than permitted emissions and failed to consider if there were additional cost-effective controls; and
- MPCA ignored cost-effective controls for the sugar beet sources.

Though we think there are improvements that need to be made to the SIP, we'd like to commend MPCA for proposing a technically sound regional haze plan for this planning period. MPCA had a robust source selection process, rejected international endpoint adjustments, used a good initial screening cost threshold, and committed to working with the NPS and other federal land managers throughout the consultation process.

I. INTRODUCTION.

Congress set aside national parks and wilderness areas to protect our natural heritage for generations. Our national parks and wilderness areas are iconic, treasured landscapes, and these special places are designated "Class I areas" under the CAA and as such, their air quality is entitled to the highest level of protection. To improve air quality in our most treasured landscapes, Congress passed the visibility protection provisions of the CAA in 1977, establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution."[2] "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities."[3] In order to protect Class I areas' "intrinsic beauty and historical and archeological treasures," the regional haze program establishes a national regulatory floor and requires states to design and implement programs to curb haze-causing emissions within their jurisdictions. Each state must submit for EPA review a SIP designed to make reasonable progress toward achieving natural visibility conditions.[4]

A regional haze SIP must provide "emissions limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal."[5] The haze requirements in the CAA present an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from some of the nation's oldest and most polluting facilities.

Unfortunately, that requirement and promise is unfulfilled because the air in most Class I areas remains polluted by industrial sources, including the sources covered in our comments: US Steel – Minntac, Hibbing Taconite Co., Northshore Mining – Silver Bay, US Steel – Keetac, United Taconite LLC – Fairlane Plant, Cleveland Cliffs Minorca Mine Inc., Sherburne County Generating Plant, Boswell Energy Center, Virginia Department of Public Utilities, Hibbing Public Utilities Commission, American Crystal Sugar – East Grand Forks and Crookston, and Southern Minnesota Beet Sugar Coop. The two Class I areas most impacted by Minnesota's sources are Boundary Waters Canoe Area Wilderness ("BWCAW") and Voyageurs National Park though Class I areas across the Midwest, like Isle Royale, Wind Cave and Badlands National Parks, have hazy skies due to Minnesota's pollution sources.

Implementing the regional haze requirements promises benefits beyond improving views. Pollutants that cause visibility impairment also harm public health. For example, oxides of nitrogen ("NOx") are a precursor to ground-level ozone which is associated with respiratory disease and asthma attacks. NOx also reacts with ammonia, moisture and other compounds to form particulates that can cause and/or worsen respiratory diseases, aggravate heart disease, and lead to premature death. Similarly, sulfur dioxide ("SO_2") increases asthma symptoms, leads to increased hospital visits, and can also form particulates. NOx and SO_2 emissions also harm terrestrial and aquatic plants and animals through acid rain as well as through deposition of nitrates (which in turn cause ecosystem changes including eutrophication of mountain lakes).

[2] 42 U.S.C. § 7491(a)(1).
[3] *Id.* § 7491(g)(3).
[4] *Id.* § 7491(b)(2).
[5] *Id.* § 7491(b)(2)(B); 40 C.F.R. § 51.308(d)(1)(i)(B).

II. LEGAL FRAMEWORK.

A. The Clean Air Act's Visibility Provisions and the Regional Haze Rule.

The CAA establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."[6] To that end, EPA issued the Regional Haze Rule ("RHR"), which requires the states (or EPA where a state fails to act) to make incremental, "reasonable progress" toward eliminating human-caused visibility impairment at each Class I area by 2064.[7] Together, the CAA and EPA's RHR require states to periodically develop and implement state implementation plans ("SIPs"), each of which must contain a long-term strategy encompassing *enforceable* "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward the national goal."[8]

In developing its long-term strategy, a state must consider its anthropogenic sources of visibility impairment and evaluate different emission reduction strategies including and beyond those prescribed by the best available retrofit technology ("BART") provisions.[9] A state should consider "major and minor stationary sources, mobile sources and area sources."[10] At a minimum, a state must consider the following factors in developing its long-term strategy:

(A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
(B) Measures to mitigate the impacts of construction activities;
(C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
(D) Source retirement and replacement schedules;
(E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
(F) Enforceability of emission limitations and control measures; and
(G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.[11]

Additionally, a 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.[12]

In developing its plan, the state must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory

[6] 42 U.S.C. § 7491(a)(1).
[7] 40 C.F.R. § 51.308(d)(1), (d)(3).
[8] 42 U.S.C. § 7491(b)(2); *see also* 42 U.S.C. § 7410(a)(2); 40 C.F.R. § 51.308.
[9] 40 C.F.R. § 51.308(f).
[10] *Id.* § 51.308(f)(2)(i).
[11] *Id.* § 51.308(f)(2)(iv).
[12] 40 C.F.R. § 51.308(f)(2)(i).

upon which its strategies are based.[13] All this information is part of a state's revised SIP and subject to public notice and comment. A state's reasonable progress analysis must consider the four factors identified in the CAA and regulations.[14]

B. EPA's 2017 Revisions to the Regional Haze Rule.

On January 10, 2017, the EPA revised the RHR to strengthen and clarify the reasonable progress and consultation requirements of the rule.[15] In particular, the rule revisions make clear that a state is to *first* conduct the required Four-Factor Analysis for its sources, considering the four statutory factors, and *then* use the results from its four-factor analyses and determinations to develop the reasonable progress goals.[16] Thus, the rule "codif[ies]" EPA's "long-standing interpretation" of the SIP "planning sequence" states are required to follow:

> (1) [C]alculate baseline, current and natural visibility conditions, progress to-date and the [Uniform Rate of Progress] URP;
> (2) [D]evelop a long-term strategy for addressing regional haze by evaluating the four factors to determine what emission limits and other measures are necessary to make reasonable progress;
> (3) [C]onduct regional-scale modeling of projected future emissions under the long-term strategies to establish RPGs and then compare those goals to the URP line; and
> (4) [A]dopt a monitoring strategy and other measures to track future progress and ensure compliance.[17]

Although many states addressed the CAA's BART requirements in their initial regional haze plans, EPA's 2017 revisions to the RHR make clear that BART was not a once-and-done requirement. Indeed, states "will need" to reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically-achievable controls in the second planning period.[18]

To the extent that a state declines to evaluate additional pollution controls for any source relied upon to achieve reasonable progress based on that source's planned retirement or decline in utilization, it must incorporate those operating parameters or assumptions as enforceable limitations in the second planning period SIP. The CAA requires that "[e]ach state implementation plan . . . *shall*" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act.[19] The RHR similarly requires each state to include "enforceable emission limitations" as necessary to ensure reasonable progress toward the national visibility goal.[20]

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[13] 40 C.F.R. § 51.308(f)(2)(i).
[14] *See* 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i) ("the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment.").
[15] *See generally* 82 Fed. Reg. 3,078 (Jan. 10, 2017).
[16] 82 Fed. Reg. at 3,090-91.
[17] *Id.*
[18] 82 Fed. Reg. at 3,083; *see also id.* at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").
[19] 42 U.S.C. § 7410(a)(2)(A).
[20] *See* 40 C.F.R. § 51.308(d)(3) ("The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas.")

Therefore, where the state relies on a sources' plans to permanently cease operations or projects that future operating parameters (*e.g.*, limited hours of operation or capacity utilization) will differ from past practice, or if this projection exempts additional pollution controls as necessary to ensure reasonable progress, then the state "must" make those parameters or assumptions into enforceable limitations.[21]

Finally, the state's SIP revisions must meet certain procedural and consultation requirements.[22] The state must consult with the FLM and look to the FLMs' expertise of the lands and knowledge of the way pollution harms them to guide the state to ensure SIPs do what they must to help restore natural skies. The rule also requires that in "developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers."[23]

C. EPA's July 8, 2021 Regional Haze Clarification Memorandum.

On July 8, 2021, EPA issued a memo which additionally clarified certain aspects of the revised RHR and provided further information to states and EPA regional offices regarding their planning obligations for the Second Planning Period.[24] EPA's July 2021 "Clarification Memo" confirms that certain aspects of MPCA's proposed SIP are fundamentally flawed and cannot be approved. Particularly relevant here, EPA made clear that states must secure additional emission reductions that build on progress already achieved, and there is an expectation that reductions are additive to ongoing and upcoming reductions under other CAA programs.[25] In evaluating sources for emission reductions, EPA emphasized that:

> Source selection is a critical step in states' analytical processes. All subsequent determinations of what constitutes reasonable progress flow from states' initial decisions regarding the universe of pollutants and sources they will consider for the second planning period. States cannot reasonably determine that they are making reasonable progress if they have not adequately considered the contributors to visibility impairment. Thus, while states have discretion to reasonably select sources, this analysis should be designed and conducted to ensure that source selection results

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[21] 40 C.F.R. §§ 51.308(i); (d)(3) ("The long-term strategy must include enforceable emissions limitations, compliance schedules . . ."); (f)(2) (the long-term strategy must include "enforceable emissions limitations"); *see also* Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 22, EPA-457/B-19-003 (Aug. 2019) [hereinafter, "August 2019 Guidance"] ("in selecting sources for control measure analysis," the state may choose "not selecting sources that have an enforceable commitment to be retired or replaced by 2028"); *id.* at 34 (To the extent a retirement or reduction in operation "is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable.") (citing 40 C.F.R. § 51.308(f)(2)); 2019 Guidance at 43 ("[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission.").

[22] For example, in addition to the Regional Haze Rule requirements, states must also follow the SIP processing requirements in 40 C.F.R. §§ 51.104, 51.102.

[23] *Id.* § 51.308(i)(3).

[24] July 8, 2021 Memo from Peter Tsirogotis to Regional Air Directors, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period at 3, https://www.epa.gov/visibility/clarifications-regardingregional-haze-state-implementation-plans-second-implementation [hereinafter, "Clarification Memo"].

[25] *Id.* at 2.

> in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[26]

Thus, it is generally not reasonable to exclude from further evaluation large sources or entire sectors of visibility impairing pollution.

For sources that have previously installed controls, states should still evaluate the "full range of potentially reasonable options for reducing emissions," including options that may "achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[27] Moreover, "[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission."[28] This means that so-called "on-the-way" measures, including anticipated shutdowns or reductions in a source's emissions or utilization, that are relied upon to forgo a four-factor analysis or to shorten the remaining useful life of a source "***must*** be included in the SIP" as enforceable emission reduction measures.[29] In addition, the Clarification Memo makes clear that a state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas. Finally, the Clarification Memo confirms EPA's recommendation that states take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.

In sum, EPA's Clarification Memo makes clear that the states' regional haze plans for the second planning period must include meaningful emission reductions to make reasonable progress towards the national goal of restoring visibility in Class I areas. The Clarification Memo confirms that MPCA's efforts to avoid emission reductions—by asserting, for example, that reductions are not necessary because visibility has improved, because reductions are anticipated at some later date or due to implementation of another program, or because a source has some level of control—is at odds with Minnesota's haze obligations under the Clean Air Act and the Regional Haze Rule itself.

III. MINNESOTA'S REGIONAL HAZE HISTORY.

In developing their Round I SIP, state officials determined that "the main pollutants contributing to visibility impairment in [these] areas are ammonium sulfate[], ammonium nitrate[], and organic carbon… The main contributors of SO_2 [(sulfate) emissions] were electric generating units ("EGUs"), while the main contributors of NOx [(nitrate) emissions] were motor vehicles…."[30] Taconite processing facilities also emit significant quantities of all three pollutants. Therefore, Minnesota's Round I SIP focused mainly on installation and operation of BART at older power plants and taconite facilities. This plan received EPA approval in 2009. In 2012, however, Minnesota updated its plans and submitted a supplemental SIP. While EPA generally approved of Minnesota's

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[26] *Id.* at 3.
[27] *Id.* at 7.
[28] *Id.* at 8.
[29] *Id.* at 8-9 (emphasis added).
[30] MPCA, REGIONAL HAZE: STATE IMPLEMENTATION PLAN, i (Dec. 2009) (available online, https://www.pca.state.mn.us/sites/default/files/aq-sip2-12.pdf).

EGU facility-related standard updates (except for at one facility), the federal government outright rejected the state's proposed updates to emission standards for taconite facilities.

Battles over taconite facility standards persisted throughout the first implementation period. EPA's rejection of Minnesota's updated standards, for instance, followed the issuance of a taconite facility-specific Federal Implementation Plan ("FIP") by EPA in February 2013. This plan, which took effect in March 2013 and purported to independently "address the deficiencies in the Minnesota SIP."[31] However, ninety-eight days later, the Eighth Circuit Court of Appeals stayed implementation of the FIP on June 14, 2013. The stay was a response to Cliffs Natural Resources Inc. ("Cliffs Natural"), ArcelorMittal USA LLC, and the State of Michigan's joint request for review of the FIP. Ultimately, EPA settled with the parties in 2015 and, in 2016, the agency published a revised FIP to the Federal Register. [32] In March 2021, EPA issued a final rule revision to the FIP, modifying NOx emission limitations for U.S. Steel's MinnTac facility (after previously denying the operator's 2013 petition to reconsider its partial disapproval of Minnesota's Regional Haze SIP).[33] However, as of August 2022, EPA had not responded to Cliff Natural's similar petition for review. As a result, EPA and industry representatives remain engaged in active settlement negotiations. [34]

Minnesota proposed its' Round II SIP in August 2022. Under this plan, MPCA relies principally on the "planned retirements of several large emission units and the continued implementation of effective control technologies that other sources already have in place" to make the requisite reasonable progress on visibility conditions at local Class I areas.[35] Similarly, MPCA erroneously relies on EPA's ongoing negotiations with taconite sources from Round I litigation to assert that the sources are effectively controlled. As discussed in Section V of our comments, that argument fails.

After conducting a thorough Q/d analysis to determine which point sources were most likely to affect visibility in Voyagers and Boundary Waters, [36] MPCA requested four-factor analyses from seventeen facilities (including "emission units at taconite processing facilities, pulp/paper mills, sugar manufacturing facilities, and electric power generation facilities").[37] For Round II, MPCA considered the four statutory factors as well as the five additional factors (including #3: "[s]ource retirement and replacement schedules") during its source selection stage.[38] Using these criteria, MPCA removed numerous units from the list of sources because the state determined that facilities

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[31] *August 2022 Draft Minnesota Regional Haze Plan* at 6.
[32] *Id.*
[33] *Id.*; EPA, *Air Plan Approval; Minnesota; Revision to Taconite Federal Implementation Plan*, 86 Fed. Reg. 12095, 12095, 12106 (Apr. 01, 2021) (revising 40 C.F.R. § 52.1235(b)(1)(iii) to increase the allowable 30-day rolling average of NOx emitted from the facility and remove the natural gas burning qualification).
[34] *August 2022 Draft Minnesota Regional Haze Plan* at 6; *see also id.* at Appendix G, PDF p. 66 (highlighting U.S. Forest Service's concern about these ongoing negotiations, and how similar talks have led to relaxation of emission limits in the past).
[35] *Id.* at 10.
[36] *See August 2022 Draft Minnesota Regional Haze Plan* at i ("MPCA used a surrogate analysis of emissions divided by distance (commonly known as a Q/d Analysis) to screen emission source impacts at Class I areas. The Q/d Analysis uses a facility's emissions (Q) in tons per year divided by the distance in kilometers (d) from the Class I areas. Ultimately, MPCA selected sources that represent roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the screening analysis for Boundary Waters and Voyageurs.")
[37] *Id.* at i, 45-47, 88.
[38] *Id.* at 58.

had either: (a) an enforceable retirement date,[39] or (b) already-effective pollution controls.[40] From there, MPCA evaluated the four-factor controls analyses submitted by remaining units' operators. As part of this process, the state both verified submitted data (e.g., emission data) and adjusted costs of controls to assess estimate which interventions would prove cost-effective.[41]

Our groups commend MPCA for its thorough analysis and evaluation of current visibility conditions in Minnesota and identification of affected Class I areas. However, we write to express our misgivings about MPCA's methodology for excusing certain sources from four-factor analyses and failing to consider whether there were cost-effective control measures that could be implemented in the meantime. Also, MPCA's reliance on retirement of major EGU point sources to achieve reasonable progress is imprudent in the absence of enforceable agreements.

IV. MPCA SHOULD MEANINGFULLY RECONSIDER AND ADAPT ITS SIP TO REFLECT COMMENTS FROM THE FLMS.

The RHR and the CAA require that states consult with the FLMs that manage the Class I Areas impacted by a state's sources. Because the FLMs' role is to manage their resources – including air quality – MPCA should meaningfully consider and adapt its SIP measures to reflect comments and suggestions from the FLMs.

States must meaningfully consider and address the insight and recommendations of the FLMs, use the FLM consultation comments to inform or amend the pre-public version of the SIP in response to the FLM comments, or provide a reasoned basis for disagreement. Given that FLM comments are based on well-documented facts and legal concerns from the Act, RHR, EPA's 2019 Guidance and Clarification Memo, the states must amend the pre-public version of their SIP in response to comments from the FLMs. MPCA failed to follow these requirements and did not respond to the comments and amend the pre-public version of the SIP, which it must do prior to submittal to EPA.

V. MPCA ERRONEOUSLY EXEMPTED SIX TACONITE MINING AND PROCESSING SOURCES FROM THE REQUIRED FOUR-FACTOR REASONABLE PROGRESS ANALYSIS.

MPCA initially identified six taconite mining and processing plants that have among the highest Q/d values of sources impacting the state's two Class I areas for Four-Factor Analyses. And yet, MPCA failed to follow the Act's requirements and neither required that the sources conduct nor conducted its own Four-Factor Analyses. As presented in the Stamper Report, the NPS's consultation comments demonstrate that cost-effective emission controls are readily available for these sources. MPCA ignored EPA's explicit directives to the State to evaluate SCR for the taconite sources in its FIP.[42] Furthermore, MPCA must not rely on erroneous justifications and fail to conduct the required Four-Factor Analysis. For example, MPCA must not rely on:

[39] *Id.* at 57, Table 31.
[40] *Id.* at 62-63, Table 32.
[41] *See generally August 2022 Draft Minnesota Regional Haze Plan* at 88, 91-95.
[42] EPA's final action explained that, "[w]e expect Minnesota and Michigan to reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods…" 81 Fed. Reg. 21672 (April 12, 2016).

- Confidential ongoing first planning period litigation and negotiations between EPA and the Minnesota taconite sources regarding BART;
- Assertions that the sources are effectively controlled; and
- EPA's previous outdated BART determinations.

As discussed below, none of these justifications provide a basis for MPCA to ignore the Act's Four-Factor Analysis requirements to evaluate and include emission controls in its SIP for the six taconite-mining and processing plants. If MPCA's final SIP fails to include these requirements, EPA must step in and propose and promulgate a FIP.

A. The Six Taconite Sources All Have High Q/d Values.

Taconite is a major industry in Minnesota with six mining and processing plants located in the State, which include:

- US Steel - Minntac
- Northshore Mining – Silver Bay
- Hibbing Taconite Co.
- US Steel Corp – Keetac
- United Taconite LLC – Fairlane Plant
- Cleveland Cliffs Minorca Mine Inc.

As explained in the Stamper Report, the taconite sources are generally among the highest Q/d values for the state's two Class I areas. The Q/d values for these six sources are shown in the two tables below. Total emissions for both tables in the second column include ammonia (NH_3), NO_X, $PM_{2.5}$, SO_2, and volatile organic compounds (VOCs).

Table 1. Taconite Plants Q/d Analysis for Boundary Waters Class I Area.[43]

Facility Name	Emissions (tons)	Distance to Class I Area (km)	Q/d	Ranking in Terms of Q/d value
US Steel - Minntac	9,473.25	95.01	99.71	1
Northshore Mining – Silver Bay	4,051.03	75.56	53.61	2
Hibbing Taconite Co.	5,619.76	122.02	46.06	5
US Steel Corp – Keetac	5,995.44	131.67	45.53	6
United Taconite LLC – Fairlane Plant	4,469.11	104.60	42.72	7

[43] *August 2022 Draft Minnesota Regional Haze Plan* at 52-54 (Table 29).

Cleveland Cliffs Minorca Mine Inc	3,522.62	87.91	40.07	8

Table 2. Taconite Plants' Q/d Analysis for Voyageurs National Park Class I Area.[44]

Facility Name	Emissions (tons)	Distance to Class I Area (km)	Q/d	Ranking in Terms of Q/d value
US Steel - Minntac	9,473.25	95.56	99.13	1
Hibbing Taconite Co.	5,619.76	104.68	53.68	3
US Steel Corp – Keetac	5,995.44	112.62	53.24	4
United Taconite LLC – Fairlane Plant	4,469.11	119.48	37.48	6
Cleveland Cliffs Minorca Mine Inc	3,522.62	97.77	36.03	7
Northshore Mining – Silver Bay	4,051.03	171.53	23.62	9

B. Contrary to MPCA's Assertions, the Taconite Sources are not "Effectively Controlled."

EPA's 2019 Guidance states that it may be reasonable for a state not to select an "effectively controlled source" for controls in its regional haze plan, but EPA was referring to sources which had pollution controls installed recently to meet a Clean Air Act requirement for which there is a low likelihood of technological advancement in controls that could provide further reasonable progress.[45] Even for sources with recent pollution controls installed or that are otherwise effectively controlled, EPA's 2019 Guidance still requires a state that does not select such a source for evaluation of controls to meet reasonable progress to "explain why the decision is consistent with the requirement to make reasonable progress, *i.e.*, why it is reasonable to assume for the purposes of efficiency and prioritization that a full Four-Factor Analysis would likely result in the conclusion that no further controls are necessary."[46] Moreover, SIPs that rely on the "effectively controlled"

[44] *August 2022 Draft Minnesota Regional Haze Plan* at 54-56 (Table 30).
[45] Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards, to EPA Air Division Directors Regions 1-10, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," at 22, EPA-457/B-19-003 (Aug. 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf. [hereinafter, "2019 Guidance"].
[46] 2019 Guidance at 22.

argument, must show that a Four-Factor Analysis would likely result in the conclusion that no further controls are necessary.[47]

Indeed, EPA has previously indicated that scrubber and SCR systems should be assessed for upgrades and that these upgrades are likely very cost-effective.[48] EPA's Clarification Memo underscores this point making clear that in evaluating reasonable progress for all sources, states should consider the "full range of potentially reasonable options for reducing emissions . . . [and] may be able to achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[49] Therefore, a state must first subject a source to a Four-Factor Analysis under section 51.308(f)(2)(i) before it is able to determine whether there are no emission reducing options available (including upgrades to existing controls).

Despite selecting the six taconite plants for Four-Factor Analysis, MPCA decided that no such analyses were required at those plants using the "effectively controlled" argument. The Stamper Report evaluated MPCA's documentation regarding whether the taconite processing facilities should be considered effectively controlled.[50] As the Stamper Report concludes, "MPCA's discussion of the current control requirements for the indurating furnaces and pelletizing furnaces at each taconite plant does not sufficiently verify that these emission units are "effectively controlled."[51]

The basis for MPCA's proposal was to rely on EPA's prior BART FIPs and for all the taconite plants determine that all are "effectively controlled" as shown in the below table.[52]

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[47] 2019 Guidance at 19; *see also* Clarification Memo.

[48] *See, e.g.*, 40 C.F.R. § 51.308(f)(2)(i) (The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment."); *see also* 82 Fed. Reg. at 3088 ("Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.").

Even if a source has a limited remaining useful life, EPA's Guidance contemplates that states consider cost-effective operational upgrades. Regional Haze Rule Guidance § II.B.3(f) ("If a control measure involves only operational changes, there typically will be only small capital costs, if any, and the useful life of the source or control equipment will not materially affect the annualized cost of the measure."); *see also* 70 Fed. Reg. 39,103, 39,171 (July 6, 2005) (where EPA has made it a point in past actions to ensure that existing controls are examined to determine if they can be cost-effectively upgraded. For instance, the 2005 BART revision to the Regional Haze Rule devotes several paragraphs to specific potential scrubber upgrades it recommends be examined.); *see also* 81 Fed. Reg. 295, 305 (Jan. 5, 2016) (EPA also demonstrated that scrubber upgrades to a number of coal-fired power plants utilizing outdated and inefficient scrubber systems were highly cost-effective, and could achieve removal efficiencies of ninety-five percent which is near the ninety-eight to ninety-nine percent removal efficiencies of newly-installed scrubber systems.); *see also* 82 Fed. Reg. 3078, 3088 (Jan. 10, 2017) (EPA noted in its 2017 Regional Haze Rule revision, EPA disapproved Texas' Four-Factor Analysis in part because "it did not include scrubber upgrades that would achieve highly cost-effective emission reductions that would lead to significant visibility improvements.").

[49] Clarification Memo at 7.

[50] Stamper Report at 9-15.

[51] Stamper Report at 15 citing *August 2022 Draft Minnesota Regional Haze Plan* at 62-63 (Table 32).

[52] Stamper Report at 10.

Table 3. MPCA's Determination of "Effectively Controlled" Emission Units at Taconite Plants.[53]

Facility Name	Emission Unit	Pollutants	Effective Control Measure	Enforceable Measure
Cleveland Cliffs Minorca Mine Inc.	Indurating Machine	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 2016 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NO_X limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.
Hibbing Taconite Co.	Indurating Furnace Lines 1, 2, and 3	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 2016 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NO_X limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.
Northshore Mining – Silver Bay	Furnace 11, Furnace 12	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 2013 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NO_X limits. See 40 CFR § 52.1235(b)(2) for SO_2 limits.
United Taconite LLC - Fairlane Plant	Lines 1 and 2 Pellet Induration	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 2016 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NOX limits. See 40 CFR § 52.1235(b)(2) for SO_2 limits.
US Steel Corp - Keetac	Grate Kiln	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 2013 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NO_X limits. See 40 CFR § 52.1235(b)(2) for SO_2 limits.
US Steel Corp - Minntac	Lines 3, 4, 5, 6, & 7 Rotary Kilns	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 2021	See 40 CFR § 52.1235(b)(1) for NO_X limits. See 40

[53] *August 2022 Draft Minnesota Regional Haze Plan* at 62-63 (Table 32).

			Regional Haze Taconite FIP.	CFR § 52.1235(b)(2) for SO_2 limits.

As EPA's 2019 Guidance explains, the RHR "anticipates the re-assessment of BART-eligible sources under the reasonable progress Rule provisions,"[54] and further instructs state SIP development by explaining that:

> [S]tates may not categorically exclude all BART-eligible sources, or all sources that installed BART controls, as candidates for selection for analysis of control measures.[55]

Thus, it was wrong for MPCA to rely on EPA's prior BART FIP determinations to exclude the six taconite sources from further analysis. MPCA must require that all the taconite sources conduct the required Four-Factor Analyses (or conduct the analyses itself) and include NO_X and SO_2 emission limitations, along with monitoring, recordkeeping and reporting requirements) in its SIP submittal to EPA.

C. MPCA Must Not Rely on the Ongoing Negotiations Between EPA and the Minnesota Taconite Sources to Exempt Sources from Controls.

MPCA must not rely on ongoing negotiations between EPA and the Minnesota taconite sources to exempt sources from controls. In its November 1, 2021 letter to another state (Wyoming) about another source (Wyodak), EPA stated that "[f]irst planning period litigation is not a basis to forego a Four-Factor Analysis for Wyodak for the second regional haze implementation period." EPA's letter further instructed that "Wyoming must perform a Four-Factor Analysis or provide a reasonable explanation for excluding Wyodak consistent with the Regional Haze Rule, EPA's 2019 Guidance, and the Clarification Memo."[56]

MPCA's SIP explained that several petitions for review remain pending before EPA from the first planning period:

- Cliffs Natural Resources Inc. petitioned U.S. EPA on November 26, 2013, to reconsider the partial disapproval of Minnesota's Regional Haze SIP.
- Cliffs Natural Resources Inc. also filed petitions for review and administrative reconsideration of the 2016 FIP.
- On February 1, 2018, U.S. Steel submitted a petition for review of EPA's denial actions of its two earlier petitions (U.S. Steel petitioned U.S. EPA on November 26, 2013, to reconsider the partial disapproval of Minnesota's Regional Haze SIP. U.S. Steel also petitioned U.S. EPA to reconsider and stay the 2013 FIP (on November 26, 2013) and 2016 FIP (on June 13, 2016)).[57]

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[54] 2019 Guidance at 25, citing 40 C.F.R. § 51.308(e)(5) ("After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than … BART, BART-eligible sources will be subject to the requirements of paragraphs (d) and (f) of this section.").
[55] 2019 Guidance at 25.
[56] *August 2022 Draft Minnesota Regional Haze Plan*, Appendix G at 46.
[57] *Id.* at 6.

MPCA must not rely on the ongoing negotiations between EPA and the Minnesota taconite sources to exempt the taconite sources from the required Four-Factor Analysis and controls in this planning period.

D. MPCA Must Not Include Emission Reductions in the RPGs that Are Not Enforceable and Must Clarify Existing Requirements.

As illustrated in the Stamper Report, the proposed SIP creates a great deal of confusion as to the current FIP requirements and the applicable deadlines for compliance.[58] MPCA must clearly lay out the current FIP requirements and the currently applicable deadlines for compliance in its regional haze plan.

Furthermore, despite EPA and the taconite sources continuing settlement discussions, and emission limitations from the first round either stayed by the court and thus likely amended as a result of the settlement discussions, MPCA included NOx emission reductions for all of the taconite plants based on EPA's FIP – except Hibbing Taconite and Cleveland Cliffs Minorca Mine – in its 2028 RPGs.[59] Moreover, based on the analysis in the Stamper Report, it appears that several of the FIP emission limits have not been achieved.[60] As discussed in the Stamper Report, Draft SIP fails to – and must – address these points.[61]

E. To Meet EPA's Expectations: MPCA Must Evaluate Additional NO_X Controls – Along with SO_2 and PM Controls – for the Taconite Pelletizing Processes.

MPCA has been on notice since April 2016, that it has been EPA's expectation that Minnesota "reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods" for controlling NO_X emissions from the taconite sources.[62] Despite this clear communication from EPA, MPCA's Draft SIP failed to reevaluate SCR with reheat for controlling NO_X emissions from the taconite sources. MPCA's final SIP must reevaluate SCR with reheat for controlling NO_X emissions from the six taconite sources.

As explained in the Stamper Report, in its comments during the FLM consultation period, the NPS evaluated tail-end SCR with reheat for United Taconite Lines 1 and 2, making revisions to cost estimates provided by United Taconite in a Four-Factor Analysis.[63] NPS found that SCR with reheat would be very cost-effective at United Taconite Line 1 at approximately $6,700/ton of NOx removed and that SCR at Line 2 would have a cost-effectiveness of $9,712/ton.[64] The NPS showed that SCR plus reheat could reduce NOx by 1,188 tons per year at United Taconite Line 1 and 1,681 tons per year at United Taconite Line 2, for a total of 2,869 tons per year.[65]

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[58] Stamper Report at 11-12.
[59] Stamper Report at 13-14.
[60] Stamper Report at 13-14 (actual NOx emission rates for the United Taconite–Fairlane Plant and the US Steel-Keetac Plant).
[61] Stamper Report at 12-15.
[62] Stamper Report at 15 citing 81 Fed. Reg. 21672, 21675 (April 12, 2016).
[63] Stamper Report at 15 citing *August 2022 Draft Minnesota Regional Haze Plan*, Appendix G at 47-54.
[64] Stamper Report at 16.
[65] Stamper Report at 16.

The NPS also recommended that MPCA evaluate an integrated approach to reduce regional haze pollutants from the taconite facilities. This would be accomplished by installing dry scrubbing and baghouse upstream of an SCR. The benefit of such a suite of controls is that it would reduce SO_2, PM, and NOx. As explained by the NPS, the reduction in SO_2 and PM upstream of the SCR would alleviate concerns with SCR catalyst poisoning and fouling of the catalyst bed, and the SCR would be much more effective at reducing NOx emissions. The NPS calculated a cost-effectiveness of this suite of controls as $6,395/ton at United Taconite Line 2, with a total of 5,172 tons of NOx, PM, and SO_2 removed.[66] These are substantive reductions in regional haze emissions with cost-effectiveness values under MPCA's cost-effectiveness threshold of $7,600/ton. Additionally, MPCA's cost-effectiveness threshold is lower than the cost-effectiveness thresholds being established for the second-round regional haze plans by several states, including Oregon ($10,000/ton)[67] and Colorado ($10,000/ton).[68]

MPCA's response to these comments were focused on the suite of multi-pollutant controls proposed by the NPS and stated that such a multi-pollutant approach "is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts."[69] MPCA failed to reschedule the start of its public notice period to accommodate consideration of the NPS comments. MPCA failed respond to the NPS's evaluation and cost analysis for SCR with reheat, which clearly showed cost-effective NOx controls for at least United Taconite Line 1, in that the cost per ton was lower than MPCA's cost-effectiveness threshold of $7,600/ton. MPCA failed to assign staff to address the FLM comments so that the planned schedule could be met. Given the size and number of staff at the agency, staff reassignment to analyze and respond to the comments would seem a common management activity. MPCA must respond to all the NPS comments, and self-imposed deadlines are not an excuse to avoid engaging with meaningful responses.

Furthermore, given that EPA notified MPCA in its 2016 taconite FIP rulemaking that it expected MPCA to "reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods,"[70] MPCA must evaluate SCR with reheat to reduce NOx emissions by up to 90% for the taconite lines at the taconite processing facilities in Minnesota.

Additionally, the NPS's evaluation of dry scrubbing, a baghouse, and SCR also warrants further evaluation by MPCA for the taconite facilities, particularly given that the taconite plants generally have the highest Q/d values of all the sources evaluated by MPCA and they are in relatively close proximity to the Minnesota's Class I areas.

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[66] *Id.*

[67] *See, e.g.,* Letter from Oregon Department of Environmental Quality to Collins Forest Products (Sept. 9, 2020), at 1-2, https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp, (Enclosure 2).

[68] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp, (Enclosure 3).

[69] *August 2022 Draft Minnesota Regional Haze Plan* at 174.

[70] 81 Fed. Reg. 21672, 21675 (April 12, 2016).

F. MPCA Must Evaluate Controls for Other Emission Units at the Taconite Plants.

1. Northshore Mining – Silver Bay Power Boilers.

The Northshore Mining – Silver Bay plant has two power boilers that are currently idled. The boilers are designed to provide process steam and electricity to the taconite plant, with excess electricity being sold to the grid. As discussed in detail in the Stamper Report, MPCA's proposed Administrative Order fails to contain the enforceable provisions necessary to allow MPCA to sidestep a Four-Factor Analysis and establish emission controls in the SIP, including assumptions regarding emissions from the restarting of the Northshore Mining power boilers in Minnesota's RPGs. MPCA must require that the source conduct the full Four-Factor Analysis and establish controls now in the SIP, so that if the source restarts operations of either of the two power boilers before 2031 "MPCA would ensure that the company would be on notice as to the level of investment that would be required if they restart the power boilers to comply with regional haze program requirements. Further, given that MPCA has not included any emissions from the Northshore Mining power boilers in its RPGs, adopting measures requiring controls if these emission units are restarted could help ensure that the units' impacts on regional haze are minimized if restarted."[71]

2. U.S. Steel – Minntac Heating Boilers and Stationary Internal Combustion Engines.

MPCA's SIP only considered emissions from the rotary kiln operations and neglected to analyzed emissions from the fuel oil-fired heating boilers diesel-fired stationary internal combustion engines at the U.S. Steel - Minntac facility. The Stamper Report found that the operating permit for the U.S. Steel - Minntac facility includes fuel oil-fired heating boilers.[72] As explained in the Stamper Report, there are ten heating boilers that were constructed prior to 1977, and thus these boilers are at least 45 years old. There are also four boilers that were installed after 1977. All of these boilers are subject to very high SO_2 limits of 2.0 lb/MMBtu heat input.[73] The older boilers are subject to total particulate matter (PM) limits of 0.6 lb/MMBtu and the post-1977 boilers are subject to 0.4 lb/MMBtu total PM limits. Based on these emission limits and the heat input capacity of these boilers, the potential to emit SO_2 and PM is very high, as shown in the table below.

Table 4. U.S. Steel - Minntac Heating Boilers Potential to Emit SO2 and Total PM Under Terms of Operating Permit, tons per year.[74]

Emission Unit Number	Heat Input Capacity, MMBtu/hr	SO_2 Limit, lb/MMBtu	SO_2 Potential to Emit, tons/year	Total PM Limit, lb/MMBtu	Total PM Potential to Emit, tons/year
EU001	104	2	911	0.6	273

[71] Stamper Report at 22.
[72] Stamper Report at 22.
[73] 2013 Minntac Permit at A-7 (pdf page 11).
[74] 2013 Minntac Permit at A-7 and A-8 (pdf pages 11-12).

Emission Unit Number	Heat Input Capacity, MMBtu/hr	SO_2 Limit, lb/MMBtu	SO_2 Potential to Emit, tons/year	Total PM Limit, lb/MMBtu	Total PM Potential to Emit, tons/year
EU002	104	2	911	0.6	273
EU003	125	2	1,095	0.6	329
EU010	24.6	2	215	0.6	65
EU011	24.6	2	215	0.6	65
SV001	104	2	911	0.6	273
SV002	104	2	911	0.6	273
SV003	125	2	1,095	0.6	329
SV010	24.6	2	215	0.6	65
SV011	24.6	2	215	0.6	65
EU004	153	2	1,340	0.4	268
EU005	153	2	1,340	0.4	268
SV004	153	2	1,340	0.4	268
SV005	153	2	1,340	0.4	268
Total PTE			***12,057***		***3,081***

As the Stamper Report explained, the Minntac operating permit also includes twenty-three diesel-fired stationary internal combustion engines.[75] Many of these engines are diesel generators. The size of these engines is not indicated in the permit. Each engine is subject to an SO_2 limit of 0.5 lb/MMBtu.[76] MPCA must evaluate control options for these engines. Some of the control options to consider include 1) replacement of one or more diesel-fired engines with electric engines, 2) replacement of one or more diesel-fired engines with Tier 4 diesel-fired engines, and 3) limiting the sulfur content of the diesel fuel used in the engines. The cost for replacing diesel-fired engines with electric engines can be quite cost-effective, especially given the fact that electrification of engines

[75] Stamper Report at 23 citing 2013 Minntac Permit at A-12 (pdf page 16).
[76] *Id.*

would reduce all emissions directly emitted from the engines, along with the fact that the maintenance requirements for the engines would be greatly reduced.[77] Regarding replacement of engines with Tier 4 engines, EPA has required engine manufacturers to meet Tier 4 emission standards since 2014. The California Air Resources Board (CARB) determined that replacement of older engines with Tier 4 engines would cost between $125/horsepower to $250/horsepower (in 2010 dollars).[78] Depending on the size of the units and typical operating hours, replacement of older engines can be quite cost effective.[79] Thus, MPCA must consider these control options for Minntac's diesel-fired stationary internal combustion engines. Replacing older engines with Tier 4 engines would greatly reduce SO_2, NOx, and PM emissions from those engines.[80]

VI. MPCA'S PROPOSED SIP FAILS TO MEET THE BASIC REQUIREMENTS OF THE REGIONAL HAZE RULE FOR SEVERAL ELECTRIC GENERATING UNITS.

A. MPCA Erroneously Relied on an Unenforceable Retirement to Exempt Sherbourne Units 1 and 2 from Cost-Effective Controls.

MPCA points to anticipated retirements and a Title V permit to avoid a meaningful analysis of potential cost-effective controls for Sherburne Units 1 and 2 ("Sherco"). As discussed, to the extent MPCA declines to conduct an analysis of the statutory reasonable progress factors based on a source's proposed retirement date, the agency must include any such retirement as an enforceable limitation in the SIP itself, to both encourage facility accountability and support its own assumptions of zero emissions after the proposed date.

Under the CAA, SIPs must "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of achieving natural visibility conditions at all Class I Areas.[81] The Regional Haze Rule echoes this requirement by highlighting that "[p]eriodic comprehensive [SIP] revisions must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress…."[82] In 2019, EPA clarified this requirement in its official 2019 Guidance, explaining that if a source will "cease operation before the end of the useful life of the controls under consideration, a state may use the enforceable shutdown date as the end of the remaining useful life. [However, in order to rely on that date] for a reasonable progress determination, *the measure [must] be included in the SIP and/or be federally enforceable*."[83]Any compliance

[77] Stamper, V. and Megan Williams, Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, and Flaring and Incineration, at 41-46 (March 6, 2020), https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp (Enclosure 4).
[78] *Id.* at 99.
[79] *Id.* at 100.
[80] *Id.* at 98 (Table 30). Note that ultra-low sulfur diesel fuel is required to be utilized in Tier 4 engines.
[81] 42 U.S.C. § 7491(b)(2).
[82] 40 C.F.R. § 51.308(f)(2); *id.* § 51.308(d)(3)(v)(F) (mandating that states consider "[e]nforceability of emission limitations and control measures" when developing their long-term regional haze strategy). *See also id.* § 51.308(f)(3) (requiring that reasonable progress goals for visibility conditions in a state's Class I area(s) be based only on "enforceable emissions limitations, compliance schedules, and other measures required under paragraph (f)(2) of this section that can be fully implemented by the end of the applicable implementation period").
[83] 2019 Guidance at 34 (emphasis added).

schedule on which a state predicates its predictions of reasonable progress must, therefore, be both practicably enforceable and included directly in each iteration of the SIP.

MPCA directly acknowledged this requirement and addressed the need for enforceable retirement dates for numerous units by issuing a series of Administrative Orders ("AOs"), which were signed by both MPCA and facility operators. These AOs, as reproduced in Appendix D of the Draft SIP, reserve MPCA's right to exercise its investigative power under Section 116.07, subdivision 9 of the Minnesota Statutes, as well as the state's right "to bring an enforcement action against, seek and collect penalties, or pursue injunctive or other relief from the Regulated Party."[84] Therefore, it seems reasonable to assume operators will comply with these AOs and, in-turn, highly likely that the four EGU point sources listed below will in fact be decommissioned by their proposed retirement dates.

- Boilers #1 and #2 at the Taconite Harbor Energy Center (to be retired by March 2022)*
- Boiler #7 at the Virginia Department of Public Utilities (to be retired by January 2025)
- Boiler #1 at Xcel Energy's Allen S. King Plant (to be retired by December 2028) [85]
  Boiler #3 at Xcel Sherburne Plant (to be retired in December 2030).[86]

The state's reliance on assuming zero emissions from Sherco Units 1 and 2, however, does not meet the necessary rigor of enforceability. Although MPCA's Administrative Order for Sherco Unit 3 states, the "Regulated Party shall permanently retire Sherco Unit 3 (EQUI 94 / EU 003) no later than December 31, 2030," there is no order regarding Units 1 or 2.[87] Instead, MPCA is relying on Xcel's current Title V permit, which indicates that the units are not permitted to continue operating after 2026, to claim that the Company's planned retirements are enforceable.[88] This is not sufficient, though. The assumed retirement of these units, and related reduction in emissions (on which MPCA relies to predict reasonable progress under the Regional Haze Rule), stems from a passing reference to a single provision in the facility's *current* Title V permit and is not part of the Title I conditions,[89] and there is no reason Xcel could not seek a renewal of its operating permit. Under the Regional Haze Rule, however, Reasonable Progress Goals adopted by a state with a Class I area must be based only on permanent emission limitations or other reductions that are adopted and enforceable in the SIP.[90] Reliance on permits in the SIP context is inconsistent with the Act, EPA's regulations and guidance. EPA's 2019 Guidance explains that the requirements in 40 C.F.R. § 51.308(d)(3)(v)(F):

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[84] *See, e.g., August 2022 Draft Minnesota Regional Haze Plan*, Appendix D, ADMINISTRATIVE ORDER BETWEEN XCEL ENERGY – ALLEN S. KING AND MPCA.
* *Compare August 2022 Draft Minnesota Regional Haze Plan* at 57 *with id.* at Appendix D (note that Table 31 in the Draft SIP document contains an expected retirement date of March 2023 for these facilities, whereas the AO contained in Appendix D says March 2022).
[85] *August 2022 Draft Minnesota Regional Haze Plan* at Appendix D.
[86] *August 2022 Draft Minnesota Regional Haze Plan*, Appendix D, ADMINISTRATIVE ORDER BY CONSENT BETWEEN XCEL ENERGY, IN THE MATTER OF SHERBURNE COUNTY GENERATING PLANT, OPERATED BY XCEL ENERGY INC.
[87] *See, August 2022 Draft Minnesota Regional Haze Plan*, Appendix D, ADMINISTRATIVE ORDER BETWEEN XCEL ENERGY – ALLEN S. KING AND MPCA.
[88] *Id.*
[89] *August 2022 Draft Minnesota Regional Haze Plan* at 57, Table 31, *referencing* MPCA, AIR INDIVIDUAL PERMIT FOR XCEL ENERGY - SHERBURNE COUNTY GENERATING PLANT: PART 70 REISSUANCE, Permit No. 14100004-101 (Aug 18, 2020) (permit available online, https://www.pca.state.mn.us/sites/default/files/14100004-101-aqpermit.pdf).
[90] 40 C.F.R. § 51.308(f)(3).

> [R]equires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.[91]

The Clean Air Act's mandate that states consider the statutory reasonable progress factors in determining cost-effective emission limitations applies to all sources; there is not an off-ramp for sources that hold permits indicating that a source anticipates retirement, especially where there is no prohibition in the permit against renewal. The regional haze emission limitations and other requirements must be embodied in the SIP. Reliance on terms and conditions in Title V permits is inconsistent with the CAA, EPA's regulations and 2019 Guidance requiring emission limitations be adopted into the SIP.

Moreover, Title V permits are only good for a period of five years and may expire under certain conditions. There is no assurance that Title V permit terms and conditions will be permanent since they may lapse. Sherco's current Title V permit will expire in September 2025.[92] This clear mismatch in dates only reinforces the imprudence of relying on an operating permit condition to determine progress on a long-term project like regional haze. MPCA's reliance on the retirement in Sherco's Title V permit as a cornerstone of its long-term regional haze strategy is, therefore, inconsistent with the CAA, RHR, and EPA 2019 Guidance.

MPCA must make these retirements enforceable conditions. EPA's 2019 Guidance on RHR SIPs indicated that "[i]nclusion in the SIP makes the emission limits permanent (meaning they cannot be subsequently revised without an EPA-approved SIP revision) and federally enforceable."[93] Therefore, by revising/replacing the Sherco AO in Appendix D with an enforceable agreement that establishes set retirement dates for each of the Sherco Units 1 and 2, MPCA can effectively claim that these units' retirement is permanent, enforceable, and appropriately relied upon when creating long-term air quality predictions. In the alternative – i.e., if MPCA will not or cannot obtain enforceable retirement agreements – the Draft SIP should contain a Four-Factor Analysis of controls for *all three* Sherco units (as discussed in more detail below regarding Unit 3).[94]

B. MPCA Erroneously Relied on an Announced Retirement of Sherburne Units 3 and Failed to Consider Whether There Are Cost-Effective Control Measures that Could Be Implemented in the Meantime.

Under MPCA's Administrative Order ("AO") Xcel Energy is obligated to retire Sherco Unit 3 by December 2030. That AO, however, includes language suggesting that the enforceability of the Order is contingent upon the Minnesota Public Utility Commission's ("MN PUC") approval of the Company's Integrate Resource Plan.[95] On September 15, 2022, the MN PUC approved Xcel's IRP, including the retirement of the Sherco Unit 3.[96] With that approval in mind, MPCA must now

[91] 2019 Guidance at 42-43.
[92] MPCA, AIR INDIVIDUAL PERMIT FOR XCEL ENERGY - SHERBURNE COUNTY GENERATING PLANT.
[93] 2019 Guidance at 43.
[94] *See generally Stamper Report* at 24-30.
[95] *August 2022 Draft Minnesota Regional Haze Plan,* Appendix D.
[96] Order Approving Plan with Modifications and Establishing Requirements for Future Filings, In re: Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy, Docket No. E-002/RP-19-368 (April 15, 2022), see attached Enclosure 5.

include the retirement of Sherco Unit 3 as a permanent and enforceable term of the SIP. Without a binding, irrevocable obligation to retire in the SIP itself, MPCA's AO does not comply with the requirements of the CAA and the Regional Haze Rule.

In any event, MPCA erroneously excluded this unit from a Four-Factor Analysis of controls assuming that retirement was sufficient to meet reasonable further progress obligations. This assumption is legally wrong.

Even where a facility has an enforceable closure date, MPCA is obligated to consider whether there are cost-effective control measures that could be implemented in the meantime.[97] Once again, EPA's Clarification Memo is instructive. There, the agency made clear that in evaluating reasonable progress for all sources, states should consider the "full range of potentially reasonable options for reducing emissions . . . that may be able to achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[98] As discussed below, there are some types of control measures that are likely to be cost-effective even within shorter timeframes.

In addition, as the Clarification Memo again makes clear, a state's reasonable progress goals *are a function of the* emission reduction *measures "in states' long-term strategies*, as well as other measures required under the CAA (that have compliance dates *on or before the end of 2028*)."[99] As an initial matter, MPCA improperly relies on emission reductions at Sherco Unit 3 that will *not* take place during the planning period, and for which the agency admits that it has not quantified the benefits.[100]

Moreover, as the attached Stamper report details, Unit 3 is not effectively controlled for SO_2 or for NOx. From 2016 to 2021, Sherco Unit 3 had an estimated achieved SO_2 removal efficiency of between 68.7% and 77.1%.[101] Since "EPA assumes … that dry FGD systems can achieve 95% control and meet a guaranteed SO2 emission rate of 0.06 lb/MMBtu," it is clear that Sherco Unit 3 is "not meeting the SO2 emission rates that should be achievable with a dry FGD system and a baghouse."[102] Thus, MPCA should evaluate options for tuning, optimizing, or upgrading Sherco Unit 3 with a dry FGD system to achieve lower SO_2 emission rates, including the following:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent

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97 *See, e.g.*, 40 C.F.R. § 51.308(f)(2)(i) (The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment."); *see also* 82 Fed. Reg. at 3088 ("Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP."). Even if a source has a limited remaining useful life, EPA's Guidance contemplates that states consider cost-effective operational upgrades. Regional Haze Rule Guidance § II.B.3(f) ("If a control measure involves only operational changes, there typically will be only small capital costs, if any, and the useful life of the source or control equipment will not materially affect the annualized cost of the measure.").

98 Clarification Memo at 7.

99 *Id.* at 6 (emphasis added).

100 *August 2022 Draft Minnesota Regional Haze Plan* at 34.

101 Stamper Report at 27.

102 Stamper Report at 28.

- Engineering redesign of atomizer or slurry injection system
- Additional equipment and maintenance
- Addition of additional scrubber module.[103]

Moreover, as the Stamper Report details, "MPCA should evaluate the use of lower sulfur coal, both as a SO2 control upgrade by itself and also in combination with dry FGD scrubber upgrades."[104] Xcel currently burns various types of coals, some with extremely high sulfur content. "If MPCA adopted a limit on the coal sulfur content requiring that coals with uncontrolled SO2 emissions no higher than 0.6 lb/MMBtu to be used at Sherco, SO2 emissions could be significantly reduced from Sherco Unit 3."[105] Simply requiring the use of low sulfur coal could change the unit's projected 2028 emissions from 8,900 tons per year of SO_2 to approximately 5,200 tons per year SO_2. MPCA could achieve this 3,700-ton reduction without requiring any additional capital expenditures as this unit already burns low sulfur coal at times.[106]

Finally, MPCA should consider whether selective non-catalytic reduction technology ("SNCR") would be a cost-effective control to install to reduce NOx emissions until the unit retires. SNCR systems can typically be installed relatively quickly, in approximately 10-13 months.[107] "If MPCA required Xcel to install SNCR at Shero Unit 3 by December 2024 and the control only operated for 6 years until the unit was retired in December of 2030, the cost-effectiveness of SNCR over a six-year period would be $8,491/ton. Although this is above MPCA's $7,600/ton cost effectiveness threshold, MPCA stated that it used a screening cost threshold of $10,000/ton,[108] and at least two other States – Oregon and Colorado- have adopted $10,000/ton cost-effectiveness thresholds as part of their regional haze plans."[109]

In short, even with the requirement to retire by 2030, the record makes clear that there are cost-effective SO_2 and NOx reduction measures and controls that could achieve significant emission reductions during the second planning period. MPCA must therefore conduct a Four-Factor Analysis of SO_2 and NOx controls for Sherco Unit 3.

C. MPCA's Control Analysis for Boswell Units 3 and 4 Is Fundamentally Flawed Because the Agency Relied on Unenforceable, Recent Emissions, Which Are Lower than Permitted Emissions, and MPCA Failed to Consider If There Were Additional Cost-Effective Controls.

MPCA determined, based on recent actual emissions, that Boswell Units 3 and 4 were "effectively controlled" for SO_2 and NOx, and exempted these two units from a Four-Factor Analysis of additional controls.[110] Because neither the existing permit nor the proposed SIP make those recent emission levels enforceable, MPCA cannot rely on those reductions to avoid

[103] Stamper Report at 28.
[104] Stamper Report at 28-29.
[105] Stamper Report at 28.
[106] Stamper Report at 28-29.
[107] Stamper Report at 28; see also Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, December 4, 2006, at 4-5, available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[108] *August 2022 Draft Minnesota Regional Haze Plan* at ii, 106.
[109] Stamper Report at 29.
[110] *Id.* at 63, 70-72.

consideration of additional controls. Accordingly, MPCA must conduct an evaluation of the four statutory reasonable progress factors for the Boswell units, or at a minimum, include the SO_2 emission limit that is currently being achieved in its SIP.

EPA's 2019 Guidance recognizes EPA's long-standing position that while the SIP is the basis for demonstrating and ensuring state plans meet the regional haze requirements, state-issued permits must complement the SIP and SIP requirements.[111] State-issued permits must not frustrate SIP requirements.[112] For example, sources with PSD permits under Title I must not hold permits that allow emissions that conflict with SIP requirements.[113]

MPCA looked at the actual emissions of these units to determine that SO_2 was effectively controlled. But those actual emissions are not practically enforceable, as required under the Clean Air Act. Since the actual emissions are six to ten times less than what is allowed under its Title V permit,[114] MPCA must impose SO_2 emission limits that reflect the level of control being achieved at the units.

In addition, MPCA should perform a Four-Factor Analysis for NOx emissions at Boswell Units 4. With respect to NOx emissions, Boswell Unit 3 is achieving NOx emission rates of 0.06 lb/MMBtu with SCR, whereas Boswell Unit 4 is achieving NOx emission rates of 0.11-0.12 lb/MMBtu with SNCR.[115] This disparity in effectiveness demonstrates that Boswell Unit 4 is not effectively controlled, as Unit 3 is achieving a 50% lower emission rate. This is because Boswell Unit 3 is equipped with low-NOx burners (LNB)/separated over-fired air (SOFA) and SCR, whereas Boswell Unit 4 is equipped with LNB/SOFA and SNCR.

EPA has acknowledged that the installation of a new pollution control required in the second round of regional haze plans may necessitate the removal or discontinuation of an existing pollution control.[116]

MPCA should have evaluated replacement of the SNCR with SCR at Boswell Unit 4 to further reduce NOx in the second round of regional haze plans. SCR is much more effective at reducing NOx than SNCR, as demonstrated in the differences between the Unit 3 and Unit 4 NOx emission rates. Further, although EPA recommends against including the sunk capital costs of existing pollution controls in the cost analysis for a new pollution control being considered to achieve reasonable compliance,[117] it is important to note that SNCR itself has a low capital cost relative to other air pollution control technologies.[118] In addition, the amount of reagent used with an SCR system is generally less than the amount of reagent used with an SNCR system, so the

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[111] 74 Fed. Reg. 13498, 13568 (April 16, 1992).
[112] Furthermore, to the extent stationary source are granted permits by rule or other mechanisms, these other categories that allow construction and operation must also complement SIP requirements.
[113] Additionally, the proposed SIP revisions fail to contain source-specific "measures to mitigate the impacts of construction activities." 40 C.F.R. § 51.308(d)(3)(v)(B).
[114] Stamper Report at 30.
[115] Stamper Report at 31.
[116] 2019 Guidance at 31.
[117] *Id.*
[118] *See* Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 7, available at https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf.

operating costs can often be lower with SCR compared to SNCR while the NOx emissions reductions are greatly improved.

Replacement of the SNCR with SCR at Boswell Unit 4 would greatly reduce NOx and therefore is an appropriate measure to evaluate to make reasonable progress towards the national visibility goal for the second implementation period and beyond.

D. MPCA Must Conduct a Four-Factor Analysis for Virginia Department of Public Utilities Units 10, 11, and 12.

The Virginia Department of Public Utilities ("VDPU") operates a cogeneration plant located in Virginia, Minnesota consisting of five boilers to generate steam and electricity. The five boilers each burn different fuels: Boiler #7 burns coal, Boilers #10, #12, and #13 each burn fracked gas, Boiler #11 co-fires wood and fracked gas. Boiler 9 previously operated, but it permanently retired in 2021. Boiler 7 has an enforceable retirement obligation of 2025. VDPU states that Boilers #12 and #13, which are either newly installed or soon to be installed, "will become the main boilers for serving the district heating system."[119]

The Four-Factor Analysis for this facility is flawed for two reasons. First, VDPU failed to analyze in its Four-Factor Analysis that in the future Boiler 11 will most likely be exclusively fueled with fracked gas. This wood- and natural gas-fired boiler is equipped with SNCR for NOx control and a multi-clone followed by an electrostatic precipitator ("ESP") for particulate matter ("PM") control. MPCA found that SCR was not cost-effective for Boiler #11.[120] However, its four-factor analysis showed widely varying actual NOx emission rates for the boiler, ranging from 0.094 lb/MMBtu to 0.175 lb/MMBtu.[121] MPCA should evaluate and disclose the NOx emission rates that correspond to burning only natural gas in Boiler #11. If NOx emission rates are projected to increase with the boiler no longer burning wood in the future, then that increase in emissions should be considered in the evaluation of SCR for NOx control. In addition, VDPU did not evaluate low NOx burners as a NOx control measure, because it stated Boiler #11 is primarily a wood-fired boiler.[122] However, if the boiler will be only operating on natural gas in the future, then installation of low NOx burners is a technically feasible NOx control that should be evaluated in a Four-Factor Analysis. Thus, MPCA must evaluate controls for Boiler #11 reflective of the unit firing only natural gas, as VDPU indicated would be its future operations, to determine appropriate NOx controls and emission limits for the boiler.

Second, MCPA did not require a Four-Factor Analysis for the three other boilers at VDPU's facility: Boilers #10, #12, and #13. MPCA did not explain or justify why it did not require four-factor analyses of controls for these boilers. VDPU states that Boilers #12 and #13, which are either newly installed or soon to be installed, "will become the main boilers for serving the district heating system."[123] Given how VDPU plans to operate these as the main boilers in the future, MPCA should ensure that these boilers are evaluated for regional haze controls in a Four-Factor Analysis. MPCA should also evaluate Boiler #10 for regional haze controls.

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[119] June 4, 2021 Virginia Department of Public Utilities Four-Factor Analysis at 2, *August 2022 Draft Minnesota Regional Haze Plan*, Appendix B at 3.
[120] Stamper Report at 32.
[121] Stamper Report at 32.
[122] Stamper Report at 32.
[123] Stamper Report at 145.

E. MPCA Must Adequately Regulate Hibbing.

Hibbing Public Utilities Commission ("HPUC") operates a cogeneration plant located in Hibbing, Minnesota consisting of four boilers to generate steam and electricity.[124] Boilers 1A, 2A, and 3A are permitted to burn coal, natural gas, used oil, and oily cellulose-based sorbents (including rags). These units do not currently have any SO_2 or NOx controls. MPCA initially found that SNCR should be required at Boilers 1A, 2A, and 3A, but then the company presented a "revised operations plan" referred to as the "Hibbing Public Utilities Restorative Plan," that presented a NOx-emission-cap obligation in lieu of a requirement to install pollution control equipment.[125] MPCA adopted this approach, which is legally inadequate for four reasons.

First, and most importantly, there are no proposed emission caps or emission limits for SO_2 for Boilers 1A, 2A, or 3A. The NPS commented that the boilers each have allowable SO_2 emission limits that are much higher than their actual SO_2 emission rates. "Specifically, the boilers have allowable SO2 limits of 4.0 lb/MMBtu, which is a very high uncontrolled SO2 limit. The NPS recommended reducing the boilers' SO2 limits to be closer to the units' actual SO2 emission rates of 0.30 lb/MMBtu to prevent backsliding."[126] HPUC rebuffed the suggestion that an SO_2 emission limit was necessary and, if it was necessary, that the limit should be 0.90 lb/MMBtu.[127] It should be noted that even if there was an effective "limit" on SO_2 of 0.90 lb/MMBtu for the boilers, that is still three times higher than the boilers' current achieved SO_2 emission rates of 0.30 lb/MMBtu.[128] The MPCA should amend the AO to require an SO_2 emission limit of 0.30 lb/MMBtu.

Second, since the MPCA already found that SNCR were cost-effective and necessary to make reasonable progress, the agency should include that requirement in its final SIP. This mirrors EPA's recommendation; EPA has found that if the state has determined that the operation of emission control equipment is necessary to make reasonable progress, "a mass-based emission limit may not be appropriate."[129]

Third, without continuous emissions monitors ("CEMs") for NOx, the Administrative Order NOx limits are unenforceable because the Order fails to specify NOx testing and test methods for assessing actual NOx emission rates.[130] It should be noted that CEMS are necessary because MPCA's NOx per 12-month emission limits would not ensure NOx is reduced on a continuous basis. In fact, if these boilers operated on a seasonal basis rather than continually throughout the year, the rolling 12-month limits could allow NOx emissions to increase daily during the operating seasons and exacerbate regional haze on those days.[131] So, if MPCA continues to use mass-based emission limits, the agency should enforce the limits on a much shorter timeframe.

[124] Stamper Report at 33.
[125] Stamper Report at 34.
[126] Stamper Report at 36.
[127] Stamper Report at 36.
[128] Stamper Report at 36.
[129] 2019 Guidance at 45.
[130] Stamper Report at 35.
[131] Stamper Report at 35.

Fourth, the Restorative Plan does not prohibit coal from being used in Boilers 1A, 2A, or 3A. If the operator wants to go with a mass-based emission limit instead of installation of pollution control equipment, foregoing this operational flexibility is required.[132]

In summary, MPCA's NOx limits of its Administrative Order for HPUC fail to assure reasonable progress due to being unenforceable and due to applying over too long of a time period. Further, the emission limits do not reflect the NOx removal capabilities of the SNCR control that MPCA found to be cost-effective for Boilers 1A, 2A, and 3A via a Four-Factor Analysis of controls.

VII. MPCA IGNORED COST-EFFECTIVE CONTROLS FOR THE THREE ANALYZED SUGAR BEET SOURCES.

Minnesota is home to multiple sugar beet processing facilities, all of which produce air pollution that contributes to haze in Class 1 areas. MPCA adequately analyzed the three facilities – American Crystal Sugar in East Grand Forks and Crookston and Southern Minnesota Beet Sugar Coop – but concluded that no emissions reductions are necessary for the sources. Our groups are concerned with this finding, similar to the concern raised by the NPS in their consultation comments included in Appendix G of the Draft SIP.

As the NPS notes in section 4 of their comments, their analyses demonstrate that "the cost of control[s] is more economical than estimated by MPCA when analyses are adjusted in accordance with the EPA Control Cost Manual (CCM)."[133] The NPS recommends the addition of DSI (with trona) and SCR at all three sources to reduce SO_2 and NOx respectively. The NPS also recommends additional controls at the Southern Minnesota Beet Sugar Coop, as noted in section 4.3.6 of their consultation documents. Taken together, these controls will limit the release of thousands of tons of SO_2 and NOx annually which could contribute to cleaner air in Class 1 areas. Our groups support the NPS-recommended controls for the sugar beet sources, and we urge MPCA to include requirements for these controls in the final SIP.

[132] Stamper Report at 36.
[133] *August 2022 Draft Minnesota Regional Haze Plan*, Appendix G at 6-37.

VIII. MPCA MUST ANALYZE ENVIRONMENTAL JUSTICE IMPACTS OF ITS REGIONAL HAZE SIP AND MUST ENSURE ITS SIP WILL REDUCE EMISSIONS AND MINIMIZE HARMS TO DISPROPORTIONATELY IMPACTED COMMUNITIES.

MPCA has both state and federal obligations to meaningfully consider and advance environmental justice in its regional haze SIP. MPCA's website explains that

> Every Minnesotan — regardless of income, race, ethnicity, color, or national origin — has the right to healthy air, sustainable lands, clean water, and a better climate. Unfortunately, too many people, especially low-income communities, communities of color, and Indigenous people, bear the disproportionate impacts of pollution and climate change. The MPCA focuses on developing strategies to reduce pollution and health disparities in communities most at-risk.[134]

Furthermore, MPCA's website explains that it is "committed" to "prioritizing environmental justice" when it develops, and implements environmental laws and regulations.[135] Furthermore, MPCA says it is "committed to making decisions that do not place disproportionate pollution burdens on these communities."[136] Finally, MPCA's website indicates that "[t]hese principles are the foundation when developing new regulations…"[137]

MPCA's website also acknowledges that environmental justice communities have higher exposures to air pollutants. For example, the website makes the following statements:

- Many studies demonstrate that low-income neighborhoods and communities of color have higher potential exposures to outdoor air pollutants and have more sources of pollution. In addition, the social, economic, and health inequities that these populations face can make them more vulnerable to the effects of air pollution. For instance, 32% of all communities in the state have air pollution-related risks above health guidelines. However, in low-income communities, the number is 46%. In communities of color, it's 91%.[138]
- Seventy-six out of about 2,000 facilities in Minnesota have modeled risks above guidelines. Only about 6% of communities in Minnesota are near one or more of these facilities. However, 14% of communities of color, which include Indigenous peoples, and 9% of low-income communities are located near one or more of these facilities.[139]
- Your likelihood of living near a facility that emits pollution at a level above health guidelines is higher if you are a person of color, Indigenous, or lower income.[140]

Despite MPCA's environmental justice principles, priorities and commitment, the only place the Draft SIP mentions environmental justice is in providing a summary of highlights of the 2019-2021 work on the Ozone Advance and PM Advance projects. The Draft SIP explained that some of the grants awarded for landscaping equipment were in areas of concern for environmental justice.[141]

Thus, despite MPCA's website explaining that the agency is "committed" to "prioritizing environmental justice" when it develops, and implements environmental laws and regulations[142] and "making decisions that do not place disproportionate pollution burdens on these communities"[143] and that "[t]hese principles are the foundation when developing new regulations…"[144]

the Proposed SIP entirely failed to take environmental justice communities into consideration as it developed plans for Minnesota's two Class I areas.

A. MPCA Completely Ignored the Environmental Justice Communities Impacted by Minnesota's Polluting Sources.

Sources that harm the air in our treasured Class I areas are also located in environmental justice areas across the State.

By evaluating the vulnerable communities and counties impacted by these sources, we believe MPCA will identify emission-reducing options that if required will improve air quality and help achieve reasonable progress in this round of regional haze rulemaking. Historically, conservation and environmental work has concerned itself with protecting nature from people and has thus "siloed" its work (*e.g.*, mainstream conservation vs. environmental justice.) While this siloed approach has led to the protection of many vulnerable habitats, it ignores the reality that people live in concert with and are a part of nature; to protect one and not the other is a job half done. By considering viewshed protection and environmental justice at the same time, we can collectively begin to dismantle the silos that exist in conservation and environmental work and chart a new path forward.

B. MPCA Can Facilitate EPA's Consideration of Environmental Justice to Comply with Federal Executive Orders.

There are specific legal grounds for considering environmental justice when determining reasonable progress controls. Under the CAA, states are permitted to include in a SIP measures that are authorized by state law but go beyond the minimum requirements of federal law.[145] Ultimately, EPA will review the Final Haze Plan that MPCA submits, and EPA will be required to ensure that its action on MPCA's Haze Plan addresses any disproportionate environmental impacts of the pollution that contributes to haze. Executive Orders in place since 1994, require federal executive agencies such as EPA to:

[M]ake achieving environmental justice part of its mission by identifying and addressing, as

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[134] MPCA, About MPCA, Environmental justice, https://www.pca.state.mn.us/about-mpca/environmental-justice. (last accessed October 7, 2022).
[135] *Id.*
[136] *Id.*
[137] *Id.*
[138] *Id.*
[139] *Id.*
[140] *Id.*
[141] *August 2022 Draft Minnesota Regional Haze Plan at 166.*
[142] *Id.*
[143] *Id.*
[144] *Id.*
[145] *See Union Elec. Co v. EPA*, 427 U.S. 246, 265 (1976) ("States may submit implementation plans more stringent than federal law requires and . . . the Administrator must approve such plans if they meet the minimum requirements of s 110(a)(2)."); *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1126 (10th Cir. 2009) (citing *Union Elec. Co.*, 427 U.S. at 265) ("In sum, the key criterion in determining the adequacy of any plan is attainment and maintenance of the national air standards . . . 'States may submit implementation plans more stringent than federal law requires and [ ] the [EPA] must approve such plans if they meet the minimum [CAA] requirements of § 110(a)(2).'").

> appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations"[146]

On January 27, 2021, the current Administration signed "Executive Order on Tackling the Climate Crisis at Home and Abroad."[147] The new Executive Order on climate change and environmental justice amended the 1994 Order and provides that:

> It is the policy of [this] Administration to organize and deploy the full capacity of its agencies to combat the climate crisis to implement a Government-wide approach that reduces climate pollution in every sector of the economy; … protects public health … delivers environmental justice …[and that] … [s]uccessfully meeting these challenges will require the Federal Government to pursue such a coordinated approach from planning to implementation, coupled with substantive engagement by stakeholders, including State, local, and Tribal governments.[148]

MPCA can facilitate EPA's compliance with these Executive Orders by considering environmental justice in its SIP submission.

C. MPCA Ignored EPA's 2019 Guidance and Clarification Memo, Which Directs States to Take Environmental Justice Concerns and Impacts Into Consideration.

EPA's Clarification Memo directs states to take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.[149] EPA's 2019 Guidance for the Second Planning Period specifies, "States may also consider any beneficial non-air quality environmental impacts."[150] This includes consideration of environmental justice in keeping with other agency policies. For example, EPA also pointed to another agency program that states could rely upon for guidance in interpreting how to apply the non-air quality environmental impacts standard:

> When there are significant potential non-air environmental impacts, characterizing those impacts will usually be very source- and place-specific. Other EPA guidance intended for use in environmental impact assessments under the National Environmental Policy Act may be informative, but not obligatory to follow, in this task.[151]

Additionally, a collection of EPA policies, guidance and directives related to the National Environmental Policy Act ("NEPA") is available at https://www.epa.gov/nepa/national-environmental-policy-act-policies-and-guidance. One of these policies concerns environmental justice.[152] MPCA should consider these sources of information in conducting a meaningful environmental justice analysis.

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[146] Exec. Order No. 12898, § 1-101, 59 Fed. Reg. 7,629 (Feb. 16, 1994), as amended by Exec. Order No. 12948, 60 Fed. Reg. 6,381 (Feb. 1, 1995).
[147] Exec. Order No. 14008, 86 Fed. Reg. 7,619 (Jan. 27, 2021).
[148] Exec. Order No. 14008 at § 201.
[149] Clarification Memo at 16.
[150] 2019 Guidance at 49.
[151] 2019 Guidance at 33.
[152] *See* EPA, "EPA Environmental Justice Guidance for National Environmental Policy Act Reviews," https://www.epa.gov/nepa/environmental-justice-guidance-national-environmental-policy-act-reviews.

D. EPA has a Repository of Directives and Material Available for MPCA to Use in Considering Environmental Justice.

In addition to the NEPA guidance directives referenced above, EPA provides a wealth of additional material.[153] The most important aspect of assessing environmental justice is to identify the areas where people are most vulnerable or likely to be exposed to different types of pollution. EPA's EJSCREEN tool can assist in that task. It uses standard and nationally consistent data to highlight places that may have higher environmental burdens and vulnerable populations.[154] Indeed, MPCA's environmental justice website notes use of the EPA's EJSCREEN tool as well as Minnesota's May 2022, "Environmental Justice Framework."[155]

E. EPA Must Consider Environmental Justice When it Reviews and Takes Action on MPCA's SIP.

As occurred in the first planning period, if a state fails to submit its SIP on time, or if EPA finds that all or part of a state's SIP does not satisfy the Regional Haze regulations, then EPA must promulgate its own Federal Implementation Plan ("FIP") to cover the SIP's inadequacy. Should EPA promulgate a FIP that reconsiders a state's Four-Factor Analysis, it is completely free to reconsider any aspect of that state' analysis. The two Presidential Executive Orders referenced above require that federal agencies integrate environmental justice principles into their decision-making. EPA has a lead role in coordinating these efforts, and recently EPA Administrator Regan directed all EPA offices to clearly integrate environmental justice considerations into their plans and actions.[156] Consequently, should EPA promulgate a FIP for Minnesota sources, it has an obligation to integrate environmental justice principles into its decision-making. The non-air quality environmental impacts of compliance portion of the third factor, is a pathway for doing so.

F. MPCA Must Consider Environmental Justice Under Title VI of the Civil Rights Act.

As EPA must consider environmental justice, so must MPCA and all other entities that accept Federal funding. Under Title VI of the Civil Rights Act of 1964, "no person shall, on the ground of race, color, national origin, sex, age or disability be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity…". MPCA has an obligation to ensure the fair treatment of communities that have been environmentally impacted by sources of pollution. That means going beyond the flawed analysis conducted and ensuring "meaningful involvement" of impacted communities; environmental justice also requires

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[153] *See* EPA, "Learn About Environmental Justice," https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.

[154] *See* EPA, "EPA EJSCREEN: Environmental Justice Screening and Mapping Tool, Additional Resources and Tools Related to EJSCREEN," https://www.epa.gov/ejscreen/additional-resources-and-tools-related-ejscreen.

[155] Environmental Justice Framework, Minnesota Pollution Control Agency, May 2022, https://www.pca.state.mn.us/about-mpca/environmental-justice.

[156] *See* EPA News Release, "EPA Administrator Announces Agency Actions to Advance Environmental Justice, Administrator Regan Directs Agency to Take Steps to Better Serve Historically Marginalized Communities," (April 7, 2021), https://www.epa.gov/newsreleases/epa-administrator-announces-agency-actions-advance-environmental-justice.

the "fair treatment" of these communities in the development and implementation of agency programs and activities, including those related to the SIP.

MPCA must conduct a thorough analysis of the current and potential effects to impacted communities from sources considered in the SIP as well as those sources identified by commenters and other stakeholders but not reviewed by MPCA. By not conducting this analysis and including the benefits of projected decline in emissions to these communities in their determination of the included emission sources, MPCA is not fulfilling its obligations under the law. Moreover, the state is making a mockery of Title VI by not using the SIP requirements to bring about the co-benefits of stronger reductions measures and reduce harms based on continued emissions.

G. MPCA's Lack of any Effort on Environmental Justice is Wholly Inadequate to Protect People Living in Environmental Justice Communities in Minnesota Affected by Minnesota's Sources.

MPCA's Proposed SIP lacks any consideration of environmental justice. MPCA failed to consider any sources that impact the environmental justice communities. Moreover, MPCA's Proposed SIP failed to include enforceable emission limitations for the polluting sources that impact the environmental justice communities. Consistent with the legal requirements, government efficiency, and the year's on injustice these communities have been subjected to from Minnesota's sources, we urge MPCA to fully and meaningfully consider all sources that impact the environmental communities. In establishing emission limitations in its SIP, MPCA must reduce impacts at *both* the Class I areas and environmental justice communities.

The population around the Virginia Department of Public Utilities plant and the major taconite facilities such as Minntac, Hibbing, Keetac, Fairlane Plant, and ArcelorMittal Minorca Mine, which are located in St. Louis County, MN, has high socioeconomic indicator percentiles including low income (72%) and unemployment rate (71). In addition, $PM_{2.5}$ and ozone environmental justice indexes in this county are high, 67% and 62%, respectively according to EJSCREEN. Moreover, the population around Silver Bay taconite facility, Sherburne Generating Plant, and Boswell Energy, located in Silver Bay MN, Becker, MN, and Cohasset, MN, respectively also has high $PM_{2.5}$ and ozone environmental justice indexes as well as high percentiles of low income and unemployment rate indicators.

IX. CONCLUSION.

While we commend MPCA for conducting a sound round II planning process with good initial actions, nonetheless, the Draft SIP will not result in reasonable progress towards improving visibility at the Class I areas its sources impact. Specifically, MPCA must:

- Meaningfully reconsider and adapt its SIP to reflect comments from the FLMs.
- Evaluate additional NO_X, SO_2 and PM controls for the taconite pelletizing processes at the six taconite sources and include enforceable emission limitations, including monitoring, recordkeeping and recording requirements in the SIP.
- Evaluate controls at other emission units at the taconite sources: Silver Bay Power Boilers and U.S. Steel – Minntac Heating Boilers and Stationary Internal Combustion Engines.

- Not include emission reductions in the RPGs from the taconite sources, which are uncertain because of ongoing negotiations between EPA, not enforceable and stayed by the court.
- Not erroneously rely on unenforceable retirement to exempt Sherbourne Units 1 and 2 from cost-effective controls.
- Not erroneously rely on an announced retirement of Sherburne Units 3 and fail to consider whether there are cost-effective control measures that could be implemented in the meantime.
- Not rely on the fundamentally flawed control analysis for Boswell Units 3 and 4, which used unenforceable, recent emissions, which are lower than permitted emissions, instead MPCA must consider if there are additional cost-effective controls.
- Conduct a Four-Factor Analysis for Virginia Department of Public Utilities Units 10, 11, and 12.
- Adequately regulate Hibbing.
- Not ignore cost-effective controls for the three sugar beet sources.
- Analyze the environmental justice impacts of its Regional Haze SIP, and ensure its SIP will reduce emissions and minimize harms to disproportionately impacted communities.

Thank you for the opportunity to provide these comments. Please be in touch with any of us with any questions.

Sincerely,

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LIST OF ENCLOSURES

All can be accessed and downloaded from here:
https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp?usp=sharing

Enclosure 1:
Review and Comments on Reasonable Progress Controls for the Minnesota Regional Haze Plan for the Second Implementation Period, which was prepared for NPCA and Sierra Club by Victoria R. Stamper (October 5, 2022).

The 11 Referenced Exhibits can be found here:
https://drive.google.com/drive/folders/1wblhchk6KZ4Lw6YI9RadKFIaLFl39OYH?usp=sharing

Enclosure 2:
Letter from Oregon Department of Environmental Quality to Collins Forest Products (Sept. 9, 2020), https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp.

Enclosure 3:
Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, Nov. 17 to 19, 2021 Public Hearing, Prehearing Statement, https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp.

Enclosure 4:
Stamper, V. and Megan Williams, Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, and Flaring and Incineration, at 41-46 (March 6, 2020), https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp.

Enclosure 5:
Order Approving Plan with Modifications and Establishing Requirements for Future Filings, In re: Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy, Docket No. E-002/RP-19-368 (April 15, 2022), https://drive.google.com/drive/folders/10oIpMRpyOXxOj6jqzSMaedHfGrrtBlsp.

Enclosure 1

Review and Comments on Reasonable Progress Controls for the Minnesota Regional Haze Plan for the Second Implementation Period

By Victoria R. Stamper

October 5, 2022

Prepared for
National Parks Conservation Association and Sierra Club

Table of Contents

I. Introduction

The Clean Air Act's Regional Haze Program establishes a national goal of preventing future, and remedying any existing, impairment of visibility in mandatory class I Federal areas from manmade air pollution.[1] Every ten years, states must adopt periodic, comprehensive revisions to their regional haze state implementation plans (SIPs) that set forth a long-term strategy that includes enforceable emission limits and other measures as may be necessary to achieve reasonable progress towards the national visibility goal.[2] The deadline for the regional haze plan revision for the second implementation period to be submitted to EPA was July 31, 2021.[3]

To that end, in August of 2022, the Minnesota Pollution Control Agency (MPCA) issued its draft regional haze SIP revision for the second implementation period.[4] MPCA selected sources for review based on the following analysis and criteria:

> (1) MPCA quantified facilities "Q/d" value for each of the state's two Class I areas (Boundary Waters Canoe Area Wilderness (BWCAW) and Voyageur's National Park.[5] The quantity of emissions, "Q," for each facility was based on the total of NOx, SO2, PM2.5, NH3, and VOC emissions in tons per year (tpy) for the year 2016.[6] The Q/d value was based on total emissions divided by distance to nearest Class I area in kilometers (km).
>
> (2) MPCA's methodology originally included a plan to stationary sources that represent roughly the top 80% of stationary source emissions that may impact visibility at each Class I area based on the Q/d values.[7] To narrow down the list of sources to request a four-factor analysis for, MPCA categorized sources based on Q/d values, with a Q/d greater than 4 being "high priority," a Q/d between 1 and 4 being "medium priority," and a Q/d less than 1 being "low priority."[8] MPCA also consulted with the Federal Land Managers (FLMs).[9] As a result of these efforts, MPCA came up with an initial list of sources for which to request a four-factor analysis.[10]

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[1] 42 U.S.C. § 7491(a)(1).

[2] 40 C.F.R. §51.308(f)(2)(i); 42 U.S.C. § 7491(b)(2). Under the Clean Air Act, state implementation plans must include "include enforceable emission limitations and other control measures, means, or techniques . . . , as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter." 42 U.S.C. § 7491(a)(2)(A). An emission limitation is a "requirement" that "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id*. § 7602(k).

[3] 40 C.F.R. § 51.308(f).

[4] August 2022, MPCA, Minnesota's State Implementation Plan for Regional Haze, Comprehensive update for the second implementation period (2018-2028), Draft for Public Notice (hereinafter referred to as the "August 2022 Draft Minnesota Regional Haze Plan").

[5] August 2022 Draft Minnesota Regional Haze Plan at 48-56.

[6] *Id.*

[7] *Id.* 80.

[8] *Id.* at 81.

[9] *Id.* at 81-82.

[10] *Id.* at 82-84.

(3) MPCA then excluded several emission units at six facilities from a four-factor analysis based on retirements or curtailments which MPCA stated were either enforceable in the source's Title V permit or made enforceable via an administrative order.[11]

(4) MPCA excluded several emission units at nine facilities from a four-factor analysis based on MPCA's findings that these emission units were effectively controlled.[12]

Ultimately, MPCA requested four-factor analyses of controls for seventeen stationary sources.[13]

The four-factors that must be considered in determining appropriate emissions controls for the second implementation period are: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any source being evaluated for controls.[14] EPA has stated that it anticipates the cost of controls being the predominant factor in the evaluation of reasonable progress controls and that the other factors will either be considered in the cost analysis or not be a major consideration.[15] Specifically, the remaining useful life of a source is taken into account in assessing the length of time the pollution control will be in service to determine the annualized costs of controls. If there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution control is generally considered the remaining life of the source.[16]

In addition, costs of energy and water use of regional haze controls such as wet and dry flue gas desulfurization (FGD), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR) at a particular source are considered in determining the annual costs of these controls, which means that the bulk of the non-air quality and energy impacts are generally taken into account in the cost effectiveness analyses as is the remaining useful life of a unit. The length of time to install controls is not generally an issue of concern for pollution controls, as FGD systems, SCR, and SNCR all can be and have been installed within three to five years of promulgation of a requirement to install such controls.[17] In any event, EPA's August 20, 2019 regional haze guidance states that, with respect to controls needed to make reasonable progress, the "time necessary for compliance" factor does not limit the ability of

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[11] *Id.* at 57, 84.

[12] *Id.* at 62-80, 84.

[13] *Id.* at 82-83, 88.

[14] 40 C.F.R. § 51.308(f)(2)(i).

[15] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37.

[16] *Id.* at 33. While we are aware that some EGUs evaluated in this report have planned decommission dates, we are not aware that any of those dates are enforceable. Thus, for all of the EGUs evaluated for add-on NOx controls in this report, we assumed that the expected useful life of the pollution control being evaluated was the remaining useful life of the source, as directed to by EPA in its August 2019 guidance.

[17] For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan. In addition, FGDs were installed in 3-4 years from design to operation at several coal-fired power plants, including Dan E Karn Units 1 and 2, Gallatin Units 1-4, Homer City Units 1 and 2, JH Campbell Units 2 and 3, La Cygne Units 1 and 2, Michigan City Unit 12, and RM Schahfer Units 14 and 15. As will be discussed below, SNCR installation are much less complex than SCR and FGD, requiring primarily a sorbent storage and distribution system and boiler/ductwork injection ports, and thus installation of SNCR will take less time than FGD and SCR.

EPA or the states to impose controls that might not be able to be fully implemented within the planning period. More specifically, when considering the time necessary for compliance, a state may not reject a control measure because it cannot be installed and become operational until after the end of the implementation period."[18]

This report evaluates MPCA's documentation regarding whether the taconite processing facilities should be considered as effectively controlled. This report also evaluates the four-factor analyses of pollution controls for four power plants or cogeneration plants: Xcel Energy – Sherburne County Generating Plant, Minnesota Power – Boswell Energy, the Virginia Department of Public Utilities, and the Hibbing Public Utilities Commission. In brief, this report finds the following issues with the reasonable progress controls analyses for these facilities:

Taconite Processing Plants

- The taconite plants in Minnesota have the highest or close to the highest Q/d of all of the sources evaluated by MPCA, yet MPCA did not evaluate any additional controls for the facilities.
- MPCA relied on EPA's taconite federal implementation plan (FIP), as revised, to find that the plants are "effectively controlled," but it appears that most of the facilities are not yet in compliance with the EPA FIP limits. MPCA states that most plants in are the midst of settlement negotiations with EPA.
- In its 2016 revised taconite FIP, EPA stated that it expected Minnesota to "reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods."[19] Thus, MPCA must evaluate SCR with reheat as a potential NOx control for the taconite facilities in this regional haze plan.
- The National Park Service in its comments during the consultation period evaluate an integrated approach of dry scrubbing and a baghouse installed upstream of an SCR, which would reduce SO2 and PM emissions and alleviate concerns with effective SCR operation at the taconite processing lines. The National Park Service found that this suite of controls would be cost effective for United Taconite-Fairlane Plant Line 2 at $6,395/ton.
- The addition of either SCR alone or SCR in combination with dry scrubbing and a baghouse would be much more effective than the low NOx burners at the taconite indurating lines and kilns that EPA's FIP is based on. Given that it currently is not clear whether all of the taconite facilities will comply with the that EPA's FIP limits, MPCA should evaluate additional control options for the taconite production lines.
- MPCA must evaluate whether there are other emission units at each taconite processing facility that could have been evaluated for controls, such as the multiple boilers and reciprocating internal combustion engines that are in the air permit for the US Steel – Minntac plant.

[18] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 41 (it would be inconsistent with the regional haze regulations to discount an otherwise reasonable control "simply because the time frame for implementing it falls outside the regulatory established implementation period.").
[19] 81 Fed. Reg. 21672 at 21675 (Apr. 12, 2016).

Northshore Mining-Silver Bay Power Boilers

- MPCA should also evaluate and establish control requirements for the Northshore Mining – Silver Bay power boilers which are currently not operating due to a power purchase agreement with Minnesota Power that expires in 2031, but which could restart within this planning period or by 2031. MPCA's Administrative Order does not ensure that the Power Boilers could not resume operation during this planning period or later.
- Cost analyses provided herein show that SNCR would be cost effective at Power Boiler 1 at $7,400/ton and that all NOx controls (including SCR, SCR with low NOx burner and overfire air, and SNCR) would be cost effective at Power Boiler 2 at costs ranging from $4,000/ton to $6,000/ton. In addition, dry sorbent injection to achieve 40% SO2 control would be cost effective at $5,400/ton to $6,000/ton.
- MPCA should establish control requirements for the power boilers now, so that Northshore Mining is on notice as to the level of investment that would be required if they restart the power boilers to comply with regional haze program requirements.

Xcel Energy - Sherburne County Generating Plant

- Xcel Energy did not submit a four-factor analysis of controls for the Sherburne County (Sherco) units because it plans to retire Units 1 and 2 by 2026 and 2023, respectively. However, the enforceable mechanism being relied on for the retirement of Units 1 and 2 is the facility's Title V operating permit that has an expiration date of September 11, 2025. MPCA should include the anticipated retirement dates of Sherco Units 1 and 2 as an enforceable requirement of the Minnesota regional haze plan.
- For Unit 3, Xcel has proposed to shut down the unit by December 31, 2030. As part of its regional haze plan, MPCA has adopted an Administrative Order that states Unit 3 shall retire by December 2030, but the Administrative Order states that the requirement to retire does not apply if the Minnesota Public Utilities Commission (MN PUC) does not approve Xcel Energy's Integrated Resource Plan (IRP) recommendations that include shutting down Unit 3 by 2030. Since that approval by the MN PUC has now occurred, MPCA must clearly state this in its regional haze plan, so it is clear that the requirement to shut down Sherco Unit 3 by 2030 is a permanent and enforceable requirement.
- MPCA should have evaluated if there were cost-effective pollution controls that could be installed and operated until the unit shuts down in 2030. For SO2, MPCA must evaluate limiting the sulfur content of the coal burned at Sherco, which should be readily implementable due to the types of coals already shipped to the plant. In addition, MPCA must evaluate the cost effectiveness of scrubber upgrades at Unit 3 by itself and in combination with limits on coal sulfur content. Either of these SO2 control options could possibly be cost effective even if the unit only operated until 2030.
- For NOx, cost analyses provided herein show that, even with a 2030 retirement date, SNCR at Unit 3 would be cost effective at $8,500/ton. While this cost is above MPCA's $7,600/ton cost threshold, it is below the initial $10,000/ton cost effectiveness threshold considered by MPCA and is also below the $10,000 cost effectiveness threshold adopted by at least two states – Colorado and Oregon.

Minnesota Power – Boswell Energy Center

- MPCA determined that Boswell Units 3 and 4 were "effectively controlled" for SO2 and NOx and exempted these two units from a four-factor analysis of controls. However, the SO2 emission limits applicable to Boswell Units 3 and 4 under its operating permit do not reflect the level of control that the units are currently capable of achieving in practice. To ensure that Boswell Units 3 and 4 maintain SO2 emission rates at the levels of the table above, MPCA must impose SO2 emission limits that reflect the level of control being achieved at the units.
- With respect to NOx emissions, Boswell Unit 3 is achieving NOx emission rates of 0.06 lb/MMBtu with SCR, whereas Boswell Unit 4 is achieving NOx emission rates of 0.11-0.12 lb/MMBtu with SNCR.[20] This shows that Boswell Unit 4 is not effectively controlled for NOx. MPCA should have evaluated upgrading NOx controls at Boswell Unit 4 from SNCR to SCR, which would greatly reduce NOx emissions from Unit 4.

Virginia Department of Public Utilities – Boilers 9 and 11

- The Virginia Department of Public Utilities stated in its controls analysis that Boiler #11, which is a wood- and natural gas-fired boiler, will primarily burn natural gas in the future, yet it appears the four-factor analysis of NOx controls for the boiler was based on the unit's current fuel mix of wood and natural gas. If the unit will transition to only natural gas in the near future, MPCA should evaluate the NOx emission rate associated with this operating scenario and evaluate appropriate controls for gas-fired boilers. One such control that should have been evaluated is low NOx burners.
- There are three other boilers at VDPU's facility for which no controls were evaluated: Boilers #10, #12, and #13. MPCA did not explain or justify why it did not require four-factor analyses of controls for these boilers, two of which are expected to become the main boilers for serving the district heating system.

Hibbing Public Utilities Commission

- Cost effectiveness analyses were provided for SO2 and NOx controls at coal- and gas-fired Boilers 1A, 2A, and 3A and for NOx controls at a wood-fired boiler. MPCA's revised cost-effectiveness analyses for these boilers showed that SNCR would be a cost-effective NOx control for Boiler 1A, 2A, and 3A at costs ranging from $6,004/ton - $6,592/ton. However, MPCA improperly declined to require those cost-effective emission reductions.
- Instead of requiring SNCR for NOx control, MPCA adopted an Administrative Order that limits the combined NOx emissions from Boiler 1A and Boiler 2A to 134 tons per 12-month rolling sum and that limits NOx emissions from Boiler 3A to 80 tons per 12-month rolling sum. MPCA claims these requirements are consistent with the reductions that would be achieved with SNCR.
- The Administrative Order fails to include adequate NOx testing requirements to ensure that the tons per 12-month rolling limits will be complied with, and the units do not appear to have NOx continuous emissions monitoring systems (CEMs) to ensure compliance. Thus, the limits of the Administrative Order are unenforceable.

[20] *Id.*

- MPCA's NOx limits of its Administrative Order for HPUC fail to assure reasonable progress due to being unenforceable and due to applying over too long of a time period. MPCA has not adequately demonstrated that the 12-month rolling mass-based NOx limits would reflect the NOx removal efficiency of the SNCR control that MPCA found to be cost-effective for Boilers 1A, 2A, and 3A via a four-factor analysis of controls.

Comments on these and other issues are provided below.

II. Comments on MPCA's Determination of "Effectively Controlled" Sources and Sources Otherwise Exempted from Reasonable Progress Controls

A. Taconite Plants

Minnesota's taconite mining and processing plants are generally among the highest Q/d values for the state's two Class I areas. Those taconite processing facilities include the Cleveland-Cliffs Minorca Mine, Hibbing Taconite Company, Northshore Mining Company, United Taconite - Fairlane Plant, U.S. Steel - Keetac, and U.S. Steel – Minntac. The Q/d values are shown in the tables below.

Table 1. Taconite Plants Q/d Analysis for Boundary Waters Class I Area[21]

Facility Name	Emissions (tons)[a]	Distance to Class I Area (km)	Q/d	Ranking in Terms of Q/d value
US Steel - Minntac	9,473.25	95.01	99.71	1
Northshore Mining – Silver Bay	4,051.03	75.56	53.61	2
Hibbing Taconite Co.	5,619.76	122.02	46.06	5
US Steel Corp – Keetac	5,995.44	131.67	45.53	6
United Taconite LLC – Fairlane Plant	4,469.11	104.60	42.72	7
Cleveland Cliffs Minorca Mine Inc	3,522.62	87.91	40.07	8

[a] Total emissions include ammonia (NH_3), NO_x, $PM_{2.5}$, SO_2, and volatile organic compounds (VOCs).

Table 2. Taconite Plants' Q/d Analysis for Voyageurs National Park Class I Area[22]

Facility Name	Emissions (tons)[a]	Distance to Class I Area (km)	Q/d	Ranking in Terms of Q/d value
US Steel - Minntac	9,473.25	95.56	99.13	1
Hibbing Taconite Co.	5,619.76	104.68	53.68	3
US Steel Corp – Keetac	5,995.44	112.62	53.24	4
United Taconite LLC – Fairlane Plant	4,469.11	119.48	37.48	6
Cleveland Cliffs Minorca Mine Inc	3,522.62	97.77	36.03	7
Northshore Mining – Silver Bay	4,051.03	171.53	23.62	9

[a] Total emissions include NH_3, NO_x, $PM_{2.5}$, SO_2, and VOCs.

[21] August 2022 Draft Minnesota Regional Haze Plan at 52-54 (Table 29).
[22] *Id.* at 54-56 (Table 30).

Despite the taconite plants having such high Q/d values, MPCA did not require or conduct four-factor analyses of controls for these plants. Instead, MPCA considered all of the taconite plants as “effectively controlled” and not warranting further review of additional regional haze controls.

Table 3. MPCA’s Determination of “Effectively Controlled” Emission Units at Taconite Plants[23]

Facility Name	Emission Unit	Pollutants	Effective Control Measure	Enforceable Measure
Cleveland Cliffs Minorca Mine Inc.	Indurating Machine	NOx, SO2	BART emission limits (NOX and SO2) established by U.S. EPA in the 2016 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NOX limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.
Hibbing Taconite Co.	Indurating Furnace Lines 1, 2, and 3	NOx, SO2	BART emission limits (NOX and SO2) established by U.S. EPA in the 2016 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NOX limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.
Northshore Mining – Silver Bay	Furnace 11, Furnace 12	NOx, SO2	BART emission limits (NOX and SO2) established by U.S. EPA in the 2013 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NOX limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.
United Taconite LLC - Fairlane Plant	Lines 1 and 2 Pellet Induration	NOx, SO2	BART emission limits (NOX and SO2) established by U.S. EPA in the 2016 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NOX limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.
US Steel Corp - Keetac	Grate Kiln	NOx, SO2	BART emission limits (NOX and SO2) established by U.S. EPA in the 2013 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NOX limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.
US Steel Corp - Minntac	Lines 3, 4, 5, 6, & 7 Rotary Kilns	NOx, SO2	BART emission limits (NOX and SO2) established by U.S. EPA in the 2021 Regional Haze Taconite FIP.	See 40 CFR § 52.1235(b)(1) for NOX limits. See 40 CFR § 52.1235(b)(2) for SO2 limits.

[23] *Id.* at 62-63 (Table 32).

Most taconite indurating lines these taconite plants were considered subject to best available retrofit technology (BART) in the regional haze plan for the first implementation period. EPA deferred action on MPCA's BART determinations for these facilities in the first round regional haze plans and subsequently promulgated a federal implementation plan (FIP) in 2013.[24] In 2015, EPA proposed revisions to FIP requirements for NOx and SO2 emission limits for the United Taconite Fairlane Plant, Cleveland Cliffs Minorca Mine, and Hibbing Taconite plants in response to petitions for reconsideration submitted by Cliffs Natural Resources and ArcelorMittal USA,[25] and EPA finalized those FIP revisions in 2016.[26] Although US Steel filed a petition for reconsideration of SO2 and NOx limits at its Minntac and Keetac plants, EPA did not grant that petition for reconsideration of the 2013 FIP requirements at that time.[27] However, in 2020, EPA proposed revisions to the NOx limits of its FIP for the US Steel Corp. Minntac facility,[28] which it finalized in 2021.[29] As described by EPA, the U.S. taconite iron ore industry uses two types of pelletizing processes: Straight-grate and grate-kiln.[30] One major difference is that straight-grate kilns do not burn coal.[31] The EPA FIP, as revised, sets NOx limits for these pelletizing processes, specifically for the indurating furnaces or pelletizing furnaces, based on use of low NOx burners.[32]

According to MPCA, EPA and the Minnesota taconite facilities have been in continued settlement discussions since the promulgation of the 2013 and 2016 FIPs, with EPA most recently publishing a final rulemaking revising the US Steel – Minntac FIP in 2021.[33] MPCA states that deadlines in the 2013 FIP had been stayed by the 8th circuit but that stay was lifted and those deadlines still apply but then MPCA provides a confusing explanation of what the new compliance deadlines are:

> On November 15, 2016, the 8th Circuit Court of Appeals terminated the June 14, 2013 stay and extended the deadlines in the original 2013 FIP by one day for each day the court's stay was in place. From the day the 2013 FIP was effective to the day it was stayed, 98 days elapsed (March 8, 2013, to June 14, 2013). As a result, the deadlines contained in the 2013 FIP still apply (e.g., 6 months after March 8, 2013), only now from the date the stay was terminated, minus the number of days elapsed prior to the stay being issued. The deadlines contained in the 2016 FIP were never stayed and apply as promulgated (e.g., 6 months after May 12, 2016).[34]

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[24] *See* 77 Fed. Reg. 49308 (Aug. 15, 2012) (proposed FIP rulemaking) and 78 Fed. Reg. 8706 (Feb. 6, 2013) (final FIP rulemaking).
[25] 80 Fed. Reg. 64160 (Oct. 20, 2015).
[26] 81 Fed. Reg. 21672 (Apr. 12, 2016).
[27] As discussed by EPA at 80 Fed. Reg. 64163 (Oct. 22, 2015) (proposed taconite FIP revision).
[28] 85 Fed. Reg. 6125 (Feb. 4, 2020).
[29] 86 Fed. Reg. 12095 (Mar. 2, 2021).
[30] *See*, e.g., 77 Fed. Reg. 49311 (Aug. 15, 2012).
[31] *See*, e.g., 77 Fed. Reg. 49311 (Aug. 15, 2012).
[32] *See*, e.g., 77 Fed. Reg. 49311 (Aug. 15, 2012).
[33] August 2022 Draft Minnesota Regional Haze Plan at 6.
[34] *Id.* at 5-6.

It is very difficult to ascertain which of the FIP deadlines applicable to each taconite facility currently apply and which deadlines are the subject of settlement negotiations. MPCA implies that all of the taconite facilities are in settlement with EPA, except US Steel - Minntac:

> If a settlement agreement is reached with the Minnesota taconite facilities named in the FIPs (Cleveland-Cliffs Minorca Mine, Hibbing Taconite Company, Northshore Mining Company, United Taconite - Fairlane Plant, U.S. Steel - Keetac, and U.S. Steel - Minntac), U.S. EPA must publish a Federal Register notice announcing the settlement agreement, initiate a public notice and comment period, and respond to any comments received. If the settlement agreement revises portions of the Taconite FIP, the U.S. EPA must publish the revisions to the Taconite FIP, initiate a public notice and comment period, and respond to any comments received. Until then, the requirements of the Taconite FIP apply as currently promulgated. U.S. EPA proposed revisions to the FIP for U.S. Steel - Minntac on February 4, 2020, and September 29, 2020. [fn omitted]. Most recently, U.S. EPA published a final rule revising the FIP as it pertains to U.S. Steel - Minntac on March 2, 2021. [fn omitted].[35]

Although MPCA states that the taconite plants are generally in settlement negotiations with EPA, MPCA also states that until the taconite FIP is revised as a result of settlement negotiations, the requirements of the taconite FIP "apply as currently promulgated by EPA."[36] However, due to the stay of the 2013 FIP by the 8th circuit and the subsequent lifting of the stay, it is unclear when, or if, these facilities will be required to comply with the FIP. MPCA must clearly lay out the current enforceable FIP requirements and the currently applicable deadlines for compliance in its regional haze plan.

According to MPCA's Draft Regional Haze Plan, MPCA included NOx emission reductions for all of these taconite plants except Hibbing Taconite and Cleveland Cliffs Minorca Mine in its 2028 reasonable progress goals (RPGs).[37] Table 65 of the Minnesota Draft Regional Haze Plan shows the following the following modeled emission changes at the taconite facilities and whether such changes were reflected in the RPGs:

[35] *Id*. at 6.
[36] *Id.*
[37] *Id.* at 132.

Table 4. MPCA's Long Term Strategy Measures for Taconite Plants and Whether Reflected in RPGs for Boundary Waters and Voyageurs National Park.[38]

Facility Name	Emission Unit	Reflected in RPG?	NOx Reductions, tons
Cleveland Cliffs Minorca Mine Inc.	Indurating Machine	No	-2.101
Hibbing Taconite Co.	Indurating Furnace Line 1	No	-730
	Indurating Furnace Line 2	No	-846
	Indurating Furnace Line 3	No	-731
Northshore Mining – Silver Bay	Furnace 11	-	-
	Furnace 12	-	-
United Taconite LLC - Fairlane Plant	Line 1 Pellet Induration	Yes	-22
	Line 2 Pellet Induration	Yes	-549
US Steel Corp - Keetac	Grate Kiln	Yes	-3,654
US Steel Corp - Minntac	Line 3 Rotary Kiln	Yes	-405
	Line 4 Rotary Kiln	Yes	-630
	Line 5 Rotary Kiln	Yes	-410
	Line 6 Rotary Kiln	Yes	-337
	Line 7 Rotary Kiln	Yes	-398

MPCA assumed NOx emission reductions in its determination of RPGs for the United Taconite-Fairlane plant, the US Steel-Keetac plant, and the US Steel-Minntac plant. However, it appears that only the US Steel-Minntac plant is subject to revised NOx emission limitations that reflect settlement negotiations with EPA.[39]

A review of actual NOx emission rates for the United Taconite–Fairlane Plant and the US Steel-Keetac plant provided in the draft Minnesota Regional Haze Plan shows that the NOx limits of EPA's FIP applicable to these plants do not appear to have not been achieved yet with the exception of Line 1 at the Fairlane Plant, despite the compliance deadlines for the FIP limits having been passed. This is demonstrated in the tables below.

[38] *Id.* at 133-134 (Table 65).
[39] *Id.* at 6. *See also* 39 Fed. Reg. 12103 (Mar. 2, 2021).

Table 5. US Steel - Keetac NOx Emissions over 2017-2020 Compared to EPA FIP Limits[40]

Line 1 Pellet Induration	2017	2018	2019	2020	EPA FIP NOx Limits	EPA FIP Compliance Deadline
Heat Input, MMBtu/yr	2,003,400	2,578,800	2,695,350	2,036,392		
NOx emissions, tons/yr	5,009.00	5,005.00	3,306.00	1,388.00		
NOx emission rate, lb/MMBtu	5.00	3.88	2.45	2.75	1.5 lb/MMBtu, 1.2 lb/MMBtu when only natural gas is used	3/8/2016

Table 6. United Taconite-Fairlane Plant NOx Emissions Over 2017-2020 Compared to EPA FIP Limits[41]

	2017	2018	2019	2020	EPA FIP NOx Limits	EPA FIP Compliance Deadline
Line 1 Pellet Induration						
Heat Input, MMBtu/yr	1,195,604	1,387,514	1,353,678	1,442,714		
NOx emissions, tons/yr	1,341.80	1,414.40	1,383.50	1,198.00		
NOx emission rate, lb/MMBtu	2.24	2.04	2.04	1.66	2.8 lb/MMBtu firing nat gas, 1.5 lb/MMBtu when firing coal or coal/gas	6/16/2016
Line 2 Pellet Induration						
Heat Input, MMBtu/yr	2,033,156	2,305,286	2,618,174	2,393,862		
NOx emissions, tons/yr	2.36	2.93	2.59	2.63		
NOx emission rate, lb/MMBtu	1.33	1.77	1.79	1.63	2.8 lb/MMBtu firing nat gas, 1.5 lb/MMBtu when firing coal or coal/gas	12/12/2019

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[40] August 2022 Draft Minnesota Regional Haze Plan at 68-70. *See also* 40 C.F.R. 52.1235(b)(1)(i).

[41] August 2022 Draft Minnesota Regional Haze Plan at 75-76. *See also* 40 C.F.R. 52.1235(b)(1)(iv)(A)(1) and (B)(1).

The above actual emissions data and MPCA's statements regarding ongoing settlement discussions seem to imply that the emission limits for all taconite plants--except the US Steel – Minntac plant for which revised NOx emission limitations that reflect settlement negotiations with EPA were recently promulgated by EPA[42]--are not guaranteed emission reductions until EPA and the respective taconite plant owners reach settlement agreements. If that is the case, then MPCA cannot rely on NOx reductions from the United Taconite-Fairlane Plant or the US Steel-Keetac plant in its determination of RPGs. Further, MPCA must verify that the NOx emission reductions that it took into account from the US Steel-Minntac plant are consistent with the revised NOx emission limits that EPA promulgated for the facility in 2021.

While MPCA did not include emission reductions from the Cleveland Cliffs Minorca Mine Inc. or the Hibbing Taconite Company in its determination of RPGs, MPCA does list NOx emission reductions as "modeled" for these facilities.[43] MPCA should clarify what this means and whether emission reductions for these two facilities actually were modeled.

For Northshore Mining – Silver Bay, MPCA did not identify any emission reductions to meet the EPA taconite FIP. As MPCA explains, the Northshore Mining indurating furnaces 11 and 12 "did not require add-on controls to meet the NOx limits as the furnaces' design utilizes burners critically located to provide heat to the various furnace sections."[44]

MPCA's discussion of the current control requirements for the indurating furnaces and pelletizing furnaces at each taconite plant is not adequate to ensure or verify that these emission units are "effectively controlled." In fact, there are other NOx control options as well as SO2 and PM control options that should have been evaluated for the taconite processing facilities, as is discussed below.

1. MPCA Should Evaluate Additional NOx Controls, SO2 and PM Controls for the Taconite Pelletizing Processes.

Given that it is not clear that low NOx burners are truly going to reduce NOx emissions from the taconite processes to the level assumed by EPA in its FIP, MPCA was not justified in finding that the taconite lines were "effectively controlled." MPCA should have evaluated post-combustion NOx controls for the taconite lines. In its 2012 FIP, EPA did not consider SCR as technically feasible for indurating furnaces based on US Steel stating that two SCR vendors declined to bid on NOx reduction testing at the Minntac plant.[45] However, EPA took a different position in its 2016 taconite FIP in that EPA evaluated and eliminated tail-end SCR with reheat based on costs, but not based on technical infeasibility.[46] In its 2016 revised taconite FIP, EPA stated that it expected Minnesota to "reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods."[47] Thus, MPCA should evaluate SCR with reheat as a potential NOx control for the taconite facilities in this regional haze plan.

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[42] *Id.* at 6. *See also* 39 Fed. Reg. 12103 (Mar. 2, 2021).
[43] August 2022 Draft Minnesota Regional Haze Plan at 133-134 (Table 65).
[44] *Id.* at 72.
[45] 77 Fed. Reg. 49313 (Aug. 15, 2012).
[46] 81 Fed. Reg. 21675 (Apr. 12, 2016).
[47] 81 Fed. Reg. 21672 at 21675 (Apr. 12, 2016).

In its comments during the Federal Land Manager consultant period, the National Park Service (NPS) evaluated tail-end SCR with reheat for United Taconite Lines 1 and 2, making revisions to cost estimates provided by United Taconite in a four-factor analysis.[48] NPS found that SCR with reheat would be very cost-effective at United Taconite Line 1 at approximately $6,700/ton of NOx removed and that SCR at Line 2 would have a cost effectiveness of $9,712/ton. The National Park Service showed that SCR plus reheat could reduce NOx by 1,188 tons per year at United Taconite Line 1 and 1,681 tons per year at United Taconite Line 2, for a total of 2,869 tons per year.

The National Park Service also recommended that MPCA evaluate an integrated approach to reduce regional haze pollutants from the taconite facilities. This would be accomplished by installing dry scrubbing and baghouse upstream of an SCR. The benefit of such a suite of controls is that it would reduce SO2, PM, and NOx. As explained by the National Park Service, the reduction in SO2 and PM upstream of the SCR would alleviate concerns with SCR catalyst poisoning and fouling of the catalyst bed, and the SCR would be much more effective at reducing NOx emissions. The National Park Service calculated that this suite of controls would have a cost effectiveness of $6,395 per ton of pollution removed at United Taconite Line 2, with a total reduction of 5,172 tons of NOx, PM, and SO2.[49] These are substantial reductions in regional haze emissions with cost-effectiveness values under MPCA's cost effectiveness threshold of $7,600/ton.

MPCA's response to these comments were focused on the suite of multi-pollutant controls proposed by the National Park Service and stated that it such a multi-pollutant approach "is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts."[50] MPCA did not respond to the National Park Service's evaluation and cost analysis for SCR with reheat which clearly showed cost effective NOx controls for at least United Taconite Line 1, in that the cost per ton was lower than MPCA's cost-effectiveness threshold of $7,600/ton.

Given that EPA essentially notified MPCA in its 2016 taconite FIP rulemaking that it expected MPCA to "reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods,"[51] MPCA should at the minimum evaluate SCR with reheat to reduce NOx emissions by up to 90% for the taconite lines at the Taconite processing facilities in Minnesota. The NPS' evaluation of dry scrubbing, a baghouse, and SCR also warrants further evaluation by MPCA for the taconite facilities, particularly given that the taconite plants generally have the highest Q/d values of all the sources evaluated by MPCA and they are in relatively close proximity to the state's Class I areas.

2. MPCA Should Have Evaluated Controls for Other Emission Units at the Taconite Plants

In addition to evaluating controls for the taconite indurating furnaces in the regional haze plan, MPCA should have evaluated whether there are other emission units at each taconite processing facility that could be evaluated for controls. One such example is the two power boilers at Northshore Mining –

[48] August 2022 Draft Minnesota Regional Haze Plan, Appendix G at 47-54.
[49] *Id.* at 58.
[50] August 2022 Draft Minnesota Regional Haze Plan at 174.
[51] 81 Fed. Reg. 21672 at 21675 (Apr. 12, 2016).

Silver Bay. Another example is the multiple reciprocating internal combustion engines that are in the air permit for the US Steel – Minntac plant. Those emission units are discussed further below.

a) *Northshore Mining – Silver Bay Power Boilers*

The Northshore Mining – Silver Bay plant has two power boilers that are not currently operating. The boilers provided process steam and electricity to the taconite plant, with excess electricity being sold to the grid. Northshore Mining's four-factor analysis described the two boilers as follows:

> Power Boiler 1 is a natural gas, distillate fuel oil, or coal-fired boiler, which has a dry bottom, front-wall-fired configuration and a rating of 517 MMBtu/hr, or an output of 45 megawatts. Power Boiler 2 is a natural gas or coal-fired boiler, which has a dry bottom, front-walled-fired configuration and a rating of 765 MMBtu/hr, or an output of 70 megawatts.[52]

The boilers have baghouses for PM control. The boilers do not have add-on SO2 controls. Boiler 1 is equipped with low NOx burners and overfire air for NOx control (installed in 2015), but Boiler 2 has no NOx controls.[53]

Northshore describes the current operation of the boilers as follows:

> As of October 2019, Power Boilers 1 and 2 have been economically idled. In 2016, Northshore entered into a binding Power Service Agreement (PSA) with Minnesota Power to provide electricity to Northshore Mining through 2031. Silver Bay Power Company is maintaining the boilers in a manner that allows startup if and when called upon by Minnesota Power to provide emergency stability to the regional electrical grid in the event of catastrophic failure. The idled boilers may resume operation in the future after termination of the PSA, but a typical operating scenario has not yet been determined. Northshore may reevaluate the control costs in the future if an operating scenario beyond the PSA is established.[54]

The table below shows the 2016 NOx emissions from these boilers, before they were idled.

Table 7. 2017 NOx and SO2 Emissions from Northshore Mining – Silver Bay Power Boilers[55]

Northshore Mining-Silver Bay	NOx, tons/year	SO2, tons/year
Power Boiler 1	375.57	609.70
Power Boiler 2	1,008.00	780.37

MPCA states that Northshore Mining projected that Power Boilers 1 and 2 would not generate any emissions through the end of the second regional haze planning period of 2028.[56] MPCA has proposed

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[52] See Four-Factor Analysis, Northshore Mining, at 2, available at https://www.pca.state.mn.us/sites/default/files/aq-sip2-18b.pdf.
[53] *Id.* at 4.
[54] *Id.* at 3.
[55] August 2022 Draft Minnesota Regional Haze Plan at 93; EPA's Air Market Program Database data.
[56] August 2022 Draft Minnesota Regional Haze Plan at 109.

an Administrative Order that "specifies the actions the facility would take should the boilers resume operation prior to the end of 2031."[57] MPCA's Administrative Order acknowledges that Power Boilers 1 and 2 "are currently permitted to operate" but states that the units "are planned to be idled through calendar year 2031 as part of a voluntary power supply agreement that Silver Bay Power entered into with Minnesota Power to purchase grid electrical power alongside the idling of Power Boilers 1 and 2."[58] MPCA's Administrative Order does not definitively require the Silver Bay Power Boilers to be idled through 2031, because it provides for an exception when called upon by Minnesota Power "for emergency use."[59] The term "emergency use" is not defined or limited by the MPCA Administrative Order. The Administrative Order provides that, if Power Boiler or Power Boiler 2 resumes operations "other than as required under the Minnesota Power Agreement for emergency use," before the end of 2031, then Northshore must provide anticipated operating scenarios and an updated four-factor analysis of controls sixty days before the change in operating status.[60] The Order also provides in such a situation that MPCA and Northshore must revisit and revise the four-factor analysis and the Administrative Order as part of the regional haze progress report due to EPA in 2025, as part of the regional haze plan update due in 2028, or as part of the regional haze progress report due in 2033.[61] This order anticipates that the Power Boilers could be restarted before 2031 (aside from just being used under the Minnesota Power Agreement for "emergency use"), as it specifies requirements for a revised four-factor analysis if the units are restarted before 2031. Thus, this Order cannot be considered as an enforceable requirement to keep the Power Boilers 1 and 2 idled until 2031. While the Administrative Order definitively requires an updated four-factor analysis of controls sixty days before either power boiler is restarted before 2031, it does not establish a definitive timeline for MPCA's adoption of the pollutant control requirements necessary to make reasonable progress.

Absent an enforceable requirement to permanently cease operations, MPCA must establish control requirements now to be met if Northshore Mining restarts either Power Boiler, either before 2031 or after 2031 (for which operation is not currently limited). Northshore Mining submitted a four-factor analysis of controls for the two Power Boilers, but only calculated the annualized costs of control and did not evaluate cost effectiveness in terms of $/ton presumably because of its stated plan to not operate until 2031.[62] Notably, Northshore Mining did not claim a shortened remaining useful life of either power boiler in those analyses, stating that "the remaining useful life for the units are assumed to be longer than the useful life of the additional emission controls measures."[63]

MPCA revised Northshore Mining's cost analyses to take into account a lower interest rate, a lower cost of electricity, reagents, and fuel and to use a lower retrofit factor.[64] MPCA also evaluated additional control options for Boiler 2 of low NOx burners/overfire air plus SNCR or plus SCR.[65] MPCA's analysis showed that DSI at Power Boiler 1 and that all NOx controls evaluated at both power boilers, including

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[57] *Id.*
[58] August 18, 2022 Administrative Order Between MPCA and Northshore Mining Company, Findings of Fact, ¶ 12.
[59] *Id.*, Condition 1.
[60] *Id.*, Condition 3.
[61] *Id.,* Condition 4.
[62] *See* July 31, 2000 Regional Haze Four-Factor Analysis for NOx and SO2 Emissions Control, Power Boiler 1 and Power Boiler 2, in Appendix B of August 2022 Draft Minnesota Regional Haze Plan (beginning at pdf page 759).
[63] *Id.* at 10 (pdf 778 of Appendix B).
[64] August 2022 Draft Minnesota Regional Haze Plan at 109-110.
[65] *Id.*

the most effective control of SCR, should be deemed by MPCA to be cost effective controls in that the cost effectiveness did not exceed MPCA's stated cost effectiveness threshold of $7,600/ton. However, MPCA's revised cost analyses assumed an unjustifiably high retrofit factor for some controls. MPCA assumed a standard retrofit factor of 1.0 for SCR at Northshore Boiler 1 and also for low NOx burners/overfire air at Boiler 2, but MPCA assumed a retrofit factor of approximately 1.3 for SO2 controls (i.e., dry sorbent injection plus baghouse and a spray dryer absorber plus baghouse) at both Boilers 1 and 2 as well as for SCR and SNCR at Boiler 2.[66] For low NOx burner/overfire air at Boiler 2, MPCA said "no retrofit factor needed based on site-specific analysis."[67]

There are several points to keep in mind regarding the use of retrofit factors. First, t EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase in cost above the cost of SCR at a new greenfield coal-fired boiler in its SCR cost spreadsheet, because EPA's spreadsheet calls for use of a 0.8 retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit.[68]

Second, the algorithms in EPA's cost spreadsheets made available with its Control Cost Manual[69] are based on actual retrofit costs in most cases.[70] Given that most utility boilers that have retrofitted an SCR reactor were not planned or designed for an SCR reactor to be installed, the average retrofit costs that EPA's SCR cost spreadsheet calculates likely take into account some of the difficulties like lack of space and need to elevate the SCR.[71] With respect to SNCR, EPA's Control Cost Manual specifically states "estimates based on this methodology typically should *not include an additional retrofit factor for existing boilers*."[72] An SNCR system is a fairly simple NOx control, consisting of a reagent storage and injection system and simply requiring injection points in the boiler for the reagent. Similarly, dry sorbent injection (DSI) is also a fairly simple SO2 control to install. While installation of a baghouse with use of DSI could be a more involved installation, new baghouses to replace the existing baghouses may not be necessary for DSI, as will be discussed further below.

Last, the aerial view of the site[73] does not indicate significant congestion that would make the retrofitting of an SCR or an SDA any more difficult than a typical retrofit of these controls to an existing coal-fired power plant. Any retrofit of pollution controls to an already built plant has some level of difficulty due to space constraints, and the cost algorithms in the EPA cost spreadsheets and the underlying IPM cost modules are based on actual costs to retrofit these controls to existing coal-fired power plants.

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[66] *Id.*, Appendix E at pdf pages 148-190.
[67] *Id.*, Appendix E at pdf 163.
[68] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 66.
[69] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[70] *See* the "Read Me" sections of each control cost spreadsheet which states that the methodologies are based on those from the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM). See also the discussion of the IPM control cost methodologies at https://www.epa.gov/power-sector-modeling/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference.
[71] *See* EPA Control Cost Manual, Section 1, Chapter 2 – Cost Estimation: Concepts and Methodology, at 27.
[72] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction at I-26 [emphasis added].
[73] *See* https://www.google.com/maps/place/Northshore+Mining+Co/@47.2865233,-91.2605787,105m/data=!3m1!1e3!4m5!3m4!1s0x0:0xdef6d294d8bf9233!8m2!3d47.2946136!4d-91.2562261.

MPCA also understated the NOx removal efficiency that could be achieved with SCR at the power boilers. Specifically, MPCA assumed SCR could reduce NOx to 0.06 lb/MMBtu at Power Boiler 1, which reflects 85% NOx removal, and MPCA assumed SCR could reduce NOx to 0.12 lb/MMBtu at Power Boiler 2, which reflects 80% NOx removal. First, there is no justification for assuming different NOx removal efficiencies at each Power Boiler. Second, SCR can achieve NOx emission rates as low as 0.04 lb/MMBtu and NOx removal efficiencies of 90% or greater with low ammonia slip.[74]

To demonstrate how cost effective these NOx controls could be for the Northshore Mining power boilers, I used EPA's SCR and SNCR cost spreadsheets to revise the control cost estimates for the two power boilers. I assumed baseline emissions and operating characteristics based on a three-year average of 2016-2018 emissions data reported to EPA's Air Markets Program Database. I assumed a retrofit factor of "1" for both SNCR and SCR for the reasons previously described. I assumed a 30-year life of controls, which is typically the assumed useful life of these controls at a power plant. I also used the current bank prime interest rate of 6.25%,[75] whereas MPCA assumed a 3.5% interest rate.[76] I escalated cost estimates to 2021 dollars, whereas MPCA assumed a 2019 dollar cost basis.[77] The results of these revised analyses are provided below.

Table 8. Northshore Mining – Silver Bay: Revised Average Annual Cost Effectiveness of NOx Controls at Power Boilers 1 and 2.[78]

Control	Capital Cost	Operating and Maintenance Costs	Total Annual Costs, $/year	Controlled NOx Rate, lb/MMBtu	Annual NOx Reductions	Cost Effectiveness (2021 $)
Power Boiler 1						
SNCR	$5,378,647	$294,502	$727,752	0.22	98 tpy	$7,424/ton
SCR	$35,318,446	$331,077	$2,970,057	0.04	360 tpy	$8,243/ton
Power Boiler 2						
LNB/OFA[79]	$13,529,923	$277,985	$1,287,356	0.41	313 tpy	$4,109/ton
SNCR	$6,634,154	$475,079	$1,009,460	0.46	253 tpy	$3,989/ton
LNB/OFA + SNCR	$19,823,700	$799,141	$2,395,940	0.30	435 tpy	$5,509/ton
SCR	$42,951,609	$426,862	$3,635,553	0.07	712 tpy	$5,105/ton
LNB/OFA + SCR	$55,942,387	$1,010,392	$5,189,033	0.04	736 tpy	$7,047/ton

[74] *See*, e.g., EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf pages 5, 17, 23, 51, and 57, available at https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.
[75] https://fred.stlouisfed.org/series/DPRIME.
[76] August 2022 Draft Minnesota Regional Haze Plan, Appendix E.
[77] *Id.*
[78] *See* Exhibits 1 – 6 which include the costs spreadsheets for these controls at Northshore Mining Boilers 1 and 2.
[79] Northshore Mining's cost estimates for LNB/OFA were used for this calculation. It was assumed the costs were in 2019 dollars, and thus capital costs were escalated to a 2021 dollar basis using changes in the Chemical Engineering Plant Cost Indices for 2019 and 2021. Northshore Mining claimed LNB/OFA would reduce NOx by 40%, and the controlled NOx rate and annual emissions reduced was based on a 40% reduction in the 2016-2018 annual average lb/MMBtu NOx emission rate and in 2016-2018 annual NOx emissions.

As the data in the above table demonstrates, there are several cost-effective NOx control options for the Northshore Mining power boilers. MPCA states that it is using a cost-effectiveness threshold of $7,600/ton. Given that MPCA's revised cost effectiveness numbers are based on a 2019 dollar basis, the $7,600/ton cost effectiveness threshold is assumed to reflect costs in 2019. According to the Chemical Engineering Plant Cost Indices (CEPCI), costs for plant construction increased by almost 17% between 2019 and 2021.[80] Accordingly, MPCA's $7,600/ton cost effectiveness threshold equates to $8,860/ton in 2021 dollars. All of the above controls have cost effectiveness values less than $8,860/ton and, indeed, all controls but SCR at Power Boiler 1 have cost effectiveness values well below MPCA's $7,600/ton cost effectiveness threshold.

With respect to SO2 control, Northshore Mining evaluated DSI but stated that replacement baghouses would be required due to the particulate loading, and the company evaluated this suite of controls (DSI plus a baghouse) to achieve 70% SO2 reduction. However, Northshore did not evaluate the cost effectiveness of using DSI without replacement baghouses to achieve a lower level of SO2 removal. I calculated costs using EPA's DSI cost equations in its Retrofit Cost Analyzer[81] to estimate the cost effectiveness of DSI to reduce SO2 by 40% without the cost of replacing the existing baghouses. For these calculations, I relied on the SO2 emissions and operational data averaged over 2016-2018, assumed a 30-year life of controls and a 6.25% interest rate, and calculated costs in 2021 dollars. I assumed hydrated lime would be the sorbent used, as the EPA spreadsheet shows hydrate lime would have the lowest sorbent feed rate of the three sorbents that could be used which would mean the lowest additional particulate loading at the baghouse. The results are given in the table below.

Table 9. Northshore Mining – Silver Bay: Revised Average Annual Cost Effectiveness of DSI for SO2 Control at Power Boilers 1 and 2.[82]

Control	**Capital Cost**	**Operating and Maintenance Costs**	**Total Annual Costs, $/year (2021 $)**	**Annual SO2 Reductions**	**Cost Effectiveness (2021 $)**
			Power Boiler 1		
DSI at 40% SO2 Control	$1,348,578	$876,004	$1,388,396	261 tpy	$5,328/ton
			Power Boiler 2		
DSI at 40% SO2 Control	$537,682	$796,114	$1,379,100	229 tpy	$6,032/ton

The costs of DSI to achieve 40% removal of SO2 emissions at each power boiler should also be considered cost effective by MPCA, in that the costs are well below MPCA's cost effectiveness threshold.

During this implementation period when the future operation of the power boilers is not currently known, MPCA should at the very least consider adopting interim control measures that could be readily implemented if Northshore Mining restarts operation of either power boiler. SNCR and DSI can both be

[80] The Chemical Engineering Plant Cost Index for 2019 was 607.5 and it was 708.0 for 2021.
[81] https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.
[82] *See* Ex. 7, Northshore Mining Power Boilers DSI at 40% Cost Spreadsheet.

implemented fairly quickly. In a 2006 document, the Institute of Clean Air Companies indicated that SNCR could be installed in 10-13 months.[83] DSI can also be installed in timeframes less than 24 months.[84] If SCR is later required under regional haze plan for the third implementation period, the ammonia injection system of SNCR could be used with the installation of a catalytic reactor in an SCR system. SNCR could also be used with installation of low NOx burners/overfire air. Similarly, SO2 removal could be improved in the future with DSI if a new replacement baghouse was installed or possibly if a polishing baghouse was installed under control requirements during the next regional haze plan.

By establishing the controls to be installed if Northshore Mining restarts operation of either power boiler before 2031, MPCA would ensure that the company would be on notice as to the level of investment that would be required if they restart the power boilers to comply with regional haze program requirements. Further, given that MPCA has not included any emissions from the Northshore Mining power boilers in its RPGs, adopting measures requiring controls if these emission units are restarted could help ensure that the units' impacts on regional haze are minimized if restarted.

b) U.S. Steel – Minntac Heating Boilers and Stationary Internal Combustion Engines

According to the operating permit for the U.S. Steel - Minntac facility, there are several fuel oil-fired heating boilers at the Minntac facility. MPCA did not require any four-factor analysis of controls for these boilers. According to the operating permit, there are ten heating boilers that were constructed prior to 1977, and thus these boilers are at least 45 years old. There are also four boilers that were installed after 1977. All of these boilers are subject to very high SO2 limits of 2.0 lb/MMBtu heat input.[85] The older boilers are subject to total particulate matter (PM) limits of 0.6 lb/MMBtu and the post-1977 boilers are subject to 0.4 lb/MMBtu total PM limits. Based on these emission limits and the heat input capacity of these boilers, the potential to emit SO2 and PM is very high, as shown in the table below.

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[83] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, December 4, 2006, at 4-5, available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

[84] *See*, e.g., Staudt, James, Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants, prepared for Northeast States for Coordinated Air Use Management, March 31, 2011, at 4, available at https://www.nescaum.org/documents/nescaum-comments-nj-s126-petition-to-epa-20110525-combo-final.pdf. *See also* https://www.downtoearth.org.in/news/energy/in-a-first-a-thermal-power-plant-decides-to-use-dsi-technology-to-curb-so2-emission-60823. Also see a number of consent decrees that require that DSI be operational in less than two years from the date of execution, such as this one: https://www.epa.gov/enforcement/consent-decree-cinergy-corporation-et-al-duke-energy-civil-action-no-199-cv-01693-ljm.

[85] 2013 Minntac Permit at A-7 (pdf page 11).

Table 10. U.S. Steel - Minntac Heating Boilers Potential to Emit SO2 and Total PM Under Terms of Operating Permit, tons per year[86]

Emission Unit Number	Heat Input Capacity, MMBtu/hr	SO2 Limit, lb/MMBtu	SO2 Potential to Emit, tons/year	Total PM Limit, lb/MMBtu	Total PM Potential to Emit, tons/year
EU001	104	2	911	0.6	273
EU002	104	2	911	0.6	273
EU003	125	2	1,095	0.6	329
EU010	24.6	2	215	0.6	65
EU011	24.6	2	215	0.6	65
SV001	104	2	911	0.6	273
SV002	104	2	911	0.6	273
SV003	125	2	1,095	0.6	329
SV010	24.6	2	215	0.6	65
SV011	24.6	2	215	0.6	65
EU004	153	2	1,340	0.4	268
EU005	153	2	1,340	0.4	268
SV004	153	2	1,340	0.4	268
SV005	153	2	1,340	0.4	268
Total PTE			***12,057***		***3,081***

MPCA must evaluate SO2 and PM control options for these boilers. One control option would be to require use of a lower sulfur fuel, which would reduce the emissions of SO2 as well as total PM.[87] Currently, the Minntac permit does not include any limit on sulfur content of the fuel oil used in these boilers except as restrained by the SO2 emission limits.

The Minntac permit also includes twenty-three diesel-fired stationary internal combustion engines.[88] Many of these engines are diesel generators. The size of these engines is not indicated in the permit. Each engine is subject to an SO2 limit of 0.5 lb/MMBtu.[89] MPCA should evaluate control options for these engines. Some of the control options to consider include 1) replacement of one or more diesel-fired engines with electric engines, 2) replacement of one or more diesel-fired engines with Tier 4 diesel-fired engines, and 3) limiting the sulfur content of the diesel fuel used in the engines. The cost for replacing diesel-fired engines with electric engines can be quite cost-effective, especially given the fact that electrification of engines would reduce all emissions directly emitted from the engines, along with the fact that the maintenance requirements for the engines would be greatly reduced.[90] Regarding

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[86] 2013 Minntac Permit at A-7 and A-8 (pdf pages 11-12).
[87] Per EPA AP-42, Table 1.3-1, PM emissions are a function of fuel sulfur content.
[88] Permit at A-12 (pdf page 16).
[89] *Id.*
[90] *See* discussion in Stamper, V. and Megan Williams, Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines,

replacement of engines with Tier 4 engines, EPA has required engine manufacturers to meet Tier 4 emission standards since 2014. The California Air Resources Board (CARB) determined that replacement of older engines with Tier 4 engines would cost between $125/horsepower to $250/horsepower (in 2010 dollars).[91] Depending on the size of the units and typical operating hours, replacement of older engines can be quite cost effective.[92] Thus, MPCA must consider these control options for Minntac's diesel-fired stationary internal combustion engines. Replacing older engines with Tier 4 engines would greatly reduce SO2, NOx, and PM emissions from those engines.[93]

III. Xcel Energy – Sherburne County Generating Plant

The Xcel Energy – Sherburne County Generating Plant (Sherco) is a three-unit coal-fired power plant located in Becker, Minnesota in Sherburne County. The plant has a total generating capacity of 2,388 megawatts (MW). MPCA calculated a Q/d value for this plant of 52.15 for the Boundary Waters Class I area and of 50.99 for the Voyageurs National Park Class I area.[94] Sherco Units 1 and 2 are tangential-fired boilers equipped with wet limestone flue gas desulfurization (FGD) systems for SO2 control, low NOx burners and separated overfire air (LNB/SOFA) for NOx control, and wet electrostatic precipitators (WESPs) and wet FGD systems for PM control.[95] Sherco Unit 3 is a dry bottom boiler equipped with low NOx burners for NOx control, a dry lime FGD system for SO2 control, and a baghouse for SO2 and PM control.[96]

MPCA identified the emissions from the Sherburne County Generating Plant as follows:

Table 11. Xcel Energy - Sherburne County Generating Plant 2016 Emissions Data Used in Q/d Analysis[97]

NH3, tons/year	NOx, tons/year	PM2.5, tons/year	SO2, tons/year	VOC, tons/year	Total, tons/year
2.34	8,471.06	517.62	8,504.01	212.27	17,707.30

Sherco Units 1 and 2 were subject to BART in the first round regional haze plan.[98] The Sherco plant was also certified as a source of reasonably attributable visibility impairment (RAVI) by the Department of Interior.[99] MPCA adopted BART requirements for Sherco Units 1 and 2, but EPA did not finalize action on the BART requirements in lights of the RAVI certification and, instead, EPA adopted a FIP to establish

Natural Gas-Fired Heaters and Boilers, and Flaring and Incineration, March 6, 2020 (hereinafter "March 2020 Oil and Gas Sector Reasonable Progress Analysis"), at 41-46, attached as Ex. 8.

91 *Id.* at 99.

92 *Id.* at 100.

93 *Id.* at 98 (Table 30). Note that ultra-low sulfur diesel fuel is required to be utilized in Tier 4 engines.

94 August 2022 Draft Minnesota Regional Haze Plan at 82-83.

95 Based on information reported to EPA's Air Markets Program Database.

96 *Id.*

97 August 2022 Draft Minnesota Regional Haze Plan at 48 (Table 28).

98 As discussed in August 2022 Draft Minnesota Regional Haze Plan, Appendix A at 9.

99 *See* 81 Fed. Reg. 11668 (March 7, 2016).

emission limits to satisfy the RAVI certification. These emission limits and associated compliance provisions are identified in the Minnesota RAVI FIP at 40 CFR § 52.1236.

Xcel Energy did not submit a four-factor analysis of controls for the Sherco units because it stated to MPCA that it plans to shut down Units 1 and 2 by 2026 and 2023, respectively, and that it plans to shut down Unit 3 by December 31, 2030.[100] Xcel Energy cited to Permit 14100004-101 as establishing enforceable retirements dates for Units 1 and 2.[101] MPCA must explain how it will ensure that these retirement dates are permanent requirements, given that the requirements are in a permit with an expiration date of September 11, 2025. MPCA should include the anticipated retirement of Units 1 and 2 as an enforceable requirement in Minnesota's SIP.

The retirement date for Sherco Unit 3 is not yet a permit requirement or a SIP requirement. MPCA did adopt an Administrative Order on July 16, 2021 that provides that Xcel Energy "shall permanently retire Sherco Unit 3…no later than December 31, 2030."[102] Condition 3 of the Order states that the retirement of Sherco Unit 3 "will not occur if MN PUC does not approve Xcel Energy Inc's IRP recommendations to establish December 31, 2030 as the retirement date for Sherco Unit 3."[103] MPCA must affirmatively state that the Minnesota Public Utilities Commission (MN PUC) has approved Xcel Energy's Integrated Resource Plan (IRP) recommendations to establish December 31, 2030 as the retirement date for Sherco Unit 3, and it should thus make clear that the requirement of the Administrative Order to retire Sherco Unit 3 by 2030 is a permanent and enforceable requirement.

MPCA did not conduct a four-factor analysis of controls for Sherco Unit 3 for a shortened remaining useful life. MPCA should have evaluated if there were cost-effective pollution controls that could be installed to reduce regional haze pollutants in the timeframe of the second implementation period before the unit shuts down in 2030.

MPCA estimated 2028 emissions for Sherco Unit 3 would increase 15% above 2016 emissions.[104] That 15% increase reflects the following projected 2028 emissions for Sherco Unit 3:

Table 12. MPCA's Projected 2028 NOx and SO2 Emissions for Sherco Unit 3

NOx, tons/year	SO2, tons/year
4,007	8,915

Below, we provide comments on SO2 and NOx control options that MPCA should evaluate for Sherco Unit 3 notwithstanding the 2030 retirement date.

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[100] August 2022 Draft Minnesota Regional Haze Plan, Appendix B at pdf page 1560 (July 29, 2020 letter from Xcel Energy to MPCA at 1).
[101] *Id.* See also most recent permit for Sherburne Generating Plant, Permit 14100004-102, October 12, 2021, at 97 (Condition 5.57.1) and at 110 (Condition 5.58.1).
[102] August 2022 Draft Minnesota Regional Haze Plan, Appendix D at pdf pages 21-23, 7/16/2021 Administrative Order by Consent In the Matter of Sherburne County Generating Plan, Operated by Xcel Energy Inc and Owned by Xcel Energy Inc and Southern Minnesota Municipal Power Agency (SMMPA) at 2 (Order, Condition 1).
[103] *Id.*, Order Condition 3.
[104] August 2022 Draft Minnesota Regional Haze Plan at 132, 134.

A. SO2 Control Options for Sherco Unit 3

A review of the current SO2 emission rates for Sherco Unit 3 shows that the unit's annual SO2 emission rate has varied from 0.28 lb/MMBtu in 2016 to 0.17 lb/MMBtu in 2021.[105] A review of the coal burned at Sherco from data reported in the Energy Information Administration's (EIA's) Coal Data Browser shows that the plant burns subbituminous coal from a few different mines with uncontrolled SO2 emissions that have varied over 2016-2021 from 0.38 lb/MMBtu to 1.27 lb/MMBtu. This data is summarized in the table below.

Table 13. Calculated Uncontrolled SO2 in lb/MMBtu for Coal Shipped to Sherco, 2016-2021[106]

Coal Mine	2016	2017	2018	2019	2020	2021
Absaloka Mine	1.27	1.23	1.15	1.15	1.19	1.09
Belle Ayr Mine	0.47	NA	NA	NA	NA	NA
Black Thunder Mine	0.53	0.53	0.49	0.53	0.53	0.53
North Antelope Rochelle Mine	NA	0.38	0.40	0.42	0.40	0.40
Weighted Annual Average Uncontrolled SO2 across all Coals, lb/MMBtu	*0.92*	*0.86*	*0.81*	*0.75*	*0.76*	*0.63*

Note: NA means that no coal from that mine was shipped to Sherco during that year according to EIA data.

Using the weighted annual average uncontrolled SO2 emissions across all coals shipped to the Sherco plant, one can estimate the SO2 removal efficiency being achieved at Sherco Unit 3 based on its annual SO2 emission rates achieved during 2016-2021.

Table 14. Sherco Unit 3 – Estimated SO2 Removal Efficiency Being Achieved, 2016-2021[107]

	2016	2017	2018	2019	2020	2021
Weighted Average Uncontrolled SO2 Across all Coals, lb/MMBtu	0.92	0.86	0.81	0.75	0.76	0.63
Annual SO2 Emission Rate, lb/MMBtu	0.28	0.24	0.25	0.19	0.17	0.17
Estimated SO2 Removal Efficiency at Unit 3	69.1%	71.1%	68.7%	75.2%	77.1%	72.8%

[105] Based on emissions and heat input data reported to EPA's Air Markets Program Database.
[106] Data from EIA's Coal Data Browser for coal shipped to Sherco Plant. Uncontrolled SO2 emissions based on EPA's AP-42 Emission Factors in Table 1.1-3. Weighted annual average uncontrolled SO2 was calculated based on the annual heat input share of each coal mine to total coal heat input reported for all mines shipped to Sherco for the year. The EIA Coal Data Browser and calculations supporting this table are attached in Ex. 9.
[107] Based on EIA coal data summarized in above table and based on annual SO2 emission rates calculated from annual SO2 emissions and annual heat input reported for Sherco Unit 3 to EPA's Air Markets Program Database for 2016-2021.

Because it is not known if Sherco Unit 3 burned coal from all coal types that were shipped to the plant (or whether the unit primarily burned coal from one or two mines), the Unit 3 SO2 removal efficiencies are listed as an estimate. However, it seems clear that the dry FGD system at Sherco Unit 3 is not meeting the top level of SO2 control that is commonly achieved in the industry with dry FGD systems. EPA assumes in its Integrated Planning Model that dry FGD systems can achieve 95% control and meet a guaranteed SO2 emission rate of 0.06 lb/MMBtu.[108] Sherco Unit 3 is clearly not meeting the SO2 emission rates that should be achievable with a dry FGD system and a baghouse.

Thus, MPCA should evaluate options for upgrading the Sherco Unit 3 dry FGD system to achieve lower SO2 emission rates. For example, the Colorado Air Pollution Control Division (CO APCD) evaluated several scrubber upgrades for the dry FGD systems in its 2010 BART evaluation for Hayden Station Units 1 and 2, including the following:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system
- Additional equipment and maintenance.[109]

CO APCD found that adding spare atomizer parts and increasing scrubber reagent rate was extremely cost effective for Hayden Units 1 and 2 with cost effectiveness ranging from $2,047/ton to $3,202/ton.[110] MPCA has indicated that it is using an initial cost effectiveness threshold of $7,600/ton,[111] and thus scrubber upgrade costs would likely be well within the agency's own range of cost-effective controls for Minnesota's regional haze plan. Several of these control options could be readily implemented with little capital expenditure, such as use of performance additives and/or use of more reactive sorbent. Thus, MPCA must evaluate these and other scrubber upgrade options that could improve SO2 removal even if implemented over a shortened remaining useful life.

Another option MPCA should evaluate is the use of lower sulfur coal. As shown in Table 13 above, the uncontrolled SO2 emissions from the Absaloka coal used at the Sherco plant is more than twice as high as the uncontrolled SO2 emissions from the other subbituminous coal used at the facility. If MPCA adopted a limit on the coal sulfur content requiring that coals with uncontrolled SO2 emissions no higher than 0.6 lb/MMBtu to be used at Sherco, SO2 emissions could be significantly reduced from Sherco Unit 3. For example, assuming Xcel was limited to coal of no higher than 0.60 lb/MMBtu uncontrolled SO2 and that Sherco Unit 3 achieved 72.3% SO2 removal in its dry DGD system (which is the estimated average SO2 removal achieved at Sherco Unit 3 over 2016-2021), the unit's 2028 emissions would be approximately 5,200 tons per year SO2 instead of the 8,900 tons per year SO2 that

[108] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, January 2017, at 1 (available at https://www.epa.gov/system/files/documents/2021-09/attachment_5-2_sda_fgd_cost_development_methodology.pdf).
[109] *See* CO APCD, Best Available Retrofit Technology (BART) Analysis of Control Options for Public Service Company – Hayden Station, at 4 (attached as Ex. 10).
[110] *Id.*
[111] August 2022 Draft Minnesota Regional Haze Plan at ii, 106.

has been projected for Unit 3 in 2028.[112] That reflects a reduction of 3,700 ton per year of SO2 Sherco Unit 3, simply based on the unit only burning lower sulfur content coal. As demonstrated in Table 13 above, the Sherco plant already receives lower sulfur (below 0.6 lb/MMBtu uncontrolled SO2) from several coal mines. Thus, the use of lower sulfur coal is clearly a technically feasible option that could likely be implemented fairly readily (i.e., within the remaining useful life of the unit and during this regional haze planning period). MPCA must provide a cost effectiveness analysis of this readily implementable SO2 control measure. There are likely cost-effective control measures, which would require little to no capital expenditure at the plant, that could be implemented for the remaining operating years of Sherco Unit 3.

B. NOx Controls for Sherco Unit 3

With respect to NOx controls, MPCA should have evaluated the use of SNCR for Sherco Unit 3 with a shortened remaining useful life. SNCR systems can typically be installed relatively quickly. In a 2006 document, the Institute of Clean Air Companies indicated that SNCR could be installed in 10-13 months.[113] If MPCA required Sherco Unit 3 to install SNCR by the end of 2024, the SNCR system could operate for 6 years until the unit was retired in 2030. I used the EPA's SNCR cost spreadsheet[114] to calculate cost effectiveness of this control for Sherco Unit 3.

EPA's SNCR chapter of its Control Cost Manual provides a graph indicating a connection between the NOx inlet emission rate and the control efficiency, with higher NOx removal efficiencies achieved with higher inlet NOx emission rates.[115] EPA provides a best fit equation to estimate NOx removal efficiency achievable with SNCR based on NOx inlet level. That equation is:

NOx Reduction Efficiency, %, = 22.554*Inlet NOx Rate, lb/MMBtu + 16.725.[116]

Based on that equation and the 2016 annual NOx emission rate being achieved at Sherco Unit 3 of 0.13 lb/MMBtu, I calculate a NOx removal efficiency achievable with SNCR at Sherco Unit 3 of 19.6% and a controlled annual NOx rate achievable with SNCR of 0.10 lb/MMBtu.

The results of these cost effectiveness analyses are shown in Table 15 below. For the cost effectiveness calculation, I used the current bank prime interest rate of 6.25%, a 6-year life, and MPCA's 2028 projection of 2028 emissions (i.e., 15% higher than 2016 emission levels) as baseline emissions.[117]

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[112] This assumes a 15% increase in SO2 emissions and a 15% in annual heat input from 2016 levels, as MPCA assumed in its 2028 modeling for Sherco. *See* August 2022 Draft Minnesota Regional Haze Plan at 134.
[113] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, December 4, 2006, at 4-5, available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[114] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[115] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, 4/25/2019, at 1-3 to 1-4.
[116] *Id.* at Figure 1.1c (on page 1-4).
[117] *See* August 2022 Draft Minnesota Regional Haze Plan at 134.

Table 15. Cost Effectiveness of SNCR at Sherco Unit 3 Assuming a 6-Year Life, 2021 $[118]

Post-Combustion NOx Control	Annual NOx Rate with Control, lb/MMBtu	Capital Cost	Annual Operating and Maintenance Costs, $/year	Total Annualized Cost of Control, $/year	NOx Reduced from Projected 2028 Emissions, tpy	Average Annual Cost Effectiveness of SCR, $/ton (2021 $)
SNCR	0.10	$16,978,544	$2,262,485	$5,750,727	677	$8,491/ton

While the cost effectiveness of SNCR at Sherco Unit 3 assuming a 6-year life is higher than MPCA's $7,600/ton cost effectiveness threshold, MPCA stated that it used a screening cost threshold of $10,000/ton,[119] and at least two other States – Oregon and Colorado- have adopted $10,000/ton cost effectiveness thresholds as part of their regional haze plans.

C. Summary: MPCA Was Not Justified in Excluding Sherco Unit 3 from a Four-Factor Analysis of Controls

In summary, MPCA was not justified in excluding Sherco Unit 3 from a four-factor analyses of controls. The unit is not effectively controlled for SO2 or for NOx. There are likely readily implementable and cost effective SO2 and NOx controls that should have been evaluated for Sherco Unit 3 even if the unit retires by 2030, including but not limited to controls such as burning only lower sulfur coal (<0.6 lb/MMBtu SO2) and installation of SNCR. MPCA must therefore conduct a four-factor analysis of SO2 and NOx controls for Sherco Unit 3.

IV. Minnesota Power-Boswell Energy Center

Minnesota Power's Boswell Energy Center is a two-unit coal-fired power plant located in Cohasset, Minnesota in Itasca County, Minnesota. The plant has a total generating capacity of approximately 920 MW. MPCA calculated a Q/d value for this plant of 46.06 for the Boundary Waters Class I area and of 64.81 for the Voyageurs National Park Class I area.[120] Boswell Units 3 and 4 are tangentially-fired boilers both equipped baghouses for PM control. Boswell Unit 3 is also equipped with a wet FGD system for SO2 control and LNB/SOFA plus SCR for NOx control.[121] Boswell Unit 4 is equipped with DSI for SO2 control and LNB/SOFA plus SNCR for NOx control.[122]

MPCA identified the emissions from the Boswell Generating Station as follows:

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[118] *See* Ex. 11, Sherco Unit 3 SNCR Cost Spreadsheet.
[119] August 2022 Draft Minnesota Regional Haze Plan at ii, 106.
[120] *Id.* at 82-83.
[121] Based on information reported to EPA's Air Markets Program Database.
[122] Based on information reported to EPA's Air Markets Program Database.

Table 16. Minnesota Power – Boswell Generating Station 2016 Emissions Data Used in Q/d Analysis[123]

NH3, tons/year	NOx, tons/year	PM2.5, tons/year	SO2, tons/year	VOC, tons/year	Total, tons/year
1.44	4,314.49	1,186.26	3,644.25	67.69	9,214.13

The above data and the Q/d values are based on 2016 emissions and, during that time, Boswell Units 1 and 2 were operating. Neither Boswell Units 1 nor 2 have operated since 2019, according to emissions data reported to EPA's Air Markets Program Database. MPCA states the Units 1 and 2 were permanently retired in December 2018 and that the retirement has been made into an enforceable requirement.[124]

MPCA determined that Boswell Units 3 and 4 were "effectively controlled" for SO2 and NOx and exempted these two units from a four-factor analysis of controls.[125] However, the SO2 emission limits applicable to Boswell Units 3 and 4 under its operating permit do not reflect the level of control that the units are currently achieving in practice. Specifically, the 0.20 lb/MMBtu SO2 limits applicable to Boswell Units 3 and 4 are the Mercury and Air Toxics Standards (MATS) that apply as an alternative to meeting the hydrogen chloride (HCl) limits of the MATS rule.[126] The Boswell Energy Center air permit does not require that the 0.20 lb/MMBtu SO2 limit be met, if Minnesota Power chooses instead to demonstrate compliance with the HCl limit of the MATS rule.[127] Further, Boswell Units 3 and 4 are achieving SO2 emission rates much lower than the 0.20 lb/MMBtu MATS limit as shown in the table below.

Table 17. Boswell Units 3 and 4 Actual 30-Day Average SO2 Emission Rates Achieved January 2016 to June 2022, Compared to SO2 MATS Limit[128]

Unit	SO2 Limit of MATS, 30-day rolling average	Max Actual SO2 Emission Rate, 30-day average	Average Actual SO2 Emission Rate, lb/MMBtu, 30-day average
3	0.20 lb/MMBtu	0.02 lb/MMBtu	0.01 lb/MMBtu
3	0.20 lb/MMBtu	0.03 lb/MMBtu	0.03 lb/MMBtu

To ensure that Boswell Units 3 and 4 maintain SO2 emission rates at the levels of the table above, MPCA must impose SO2 emission limits that reflect the level of control being achieved at the units. Otherwise, under the MATS SO2 limit (which the units do not even have to comply with if Minnesota Power selects to demonstrate compliance with the HCl MATS limit), SO2 emissions could be allowed to increase six to ten times higher than current emissions.

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123 August 2022 Draft Minnesota Regional Haze Plan at 48 (Table 28).
124 *Id.* at 57.
125 *Id.* at 63, 70-72.
126 *Id.* at 70.
127 Minnesota Power – Boswell Energy Center, Operating Permit No. 06100004-103, issued 5/27/2022, at 32 (Condition 5.3.14).
128 Cite to and attach CAMD data

With respect to NOx emissions, Boswell Unit 3 is achieving NOx emission rates of 0.06 lb/MMBtu with SCR, whereas Boswell Unit 4 is achieving NOx emission rates of 0.11-0.12 lb/MMBtu with SNCR.[129] This data shows that Boswell Unit 4 is not effectively controlled. Indeed, Unit 3 is achieving a 50% lower emission rate with LNB/SOFA and SCR, whereas Boswell Unit 4 is equipped only with LNB/SOFA and SNCR. MPCA should have evaluated upgrading NOx controls at Boswell Unit 4. It is reasonable to consider a replacement of the SNCR with SCR at Boswell Unit 4 to further reduce NOx in the second round of regional haze plans. SCR is much more effective at reducing NOx than SNCR, as demonstrated in the differences between the Unit 3 and Unit 4 NOx emission rates.

EPA has acknowledged that the installation of a new pollutant control required in the second round of regional haze plans may necessitate the removal or discontinuation of an existing pollution control.[130] Further, although EPA recommends against including the sunk capital costs of existing pollution controls in the cost analysis for a new pollution control being considered to achieve reasonable compliance,[131] it is important to note that SNCR itself has a low capital cost (relative to other air pollution control technologies).[132] The primary capital costs of SNCR are boiler injection ports and the reagent storage and distribution system, with the bulk of the cost of control being the cost of the reagent (a recurring annual operational expense as opposed to a capital expense). In addition, the amount of reagent used with an SCR system is generally less than the amount of reagent used with an SNCR system, so the operating costs can often be lower with SCR compared to SNCR while the NOx are greatly improved. Replacement of the SNCR with SCR at Boswell Unit 4 would greatly reduce NOx and therefore is an appropriate measure to evaluate to make reasonable progress towards the national visibility goal for the second implementation period and beyond.

V. Virginia Department of Public Utilities – Boilers 9 and 11

The Virginia Department of Public Utilities (VDPU) operates a cogeneration plant located in Virginia, Minnesota consisting of five boilers to generate steam and electricity. The facility has a generating capacity of 26 MW. The facility operates and maintains an electrical distribution system, a natural gas distribution system, and a water treatment plant.[133] The five boilers each burn different fuels: Boiler #7 burns coal, Boilers #10, #12, and #13 each burn natural gas, Boiler #11 co-fires wood and natural gas.[134]

MPCA calculated a Q/d value for this plant of 7.91 for the Boundary Waters Class I area and of 7.13 for the Voyageurs National Park Class I area.[135]

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[129] *Id.*
[130] EPA's August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 31.
[131] *Id.*
[132] *See* Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 7, available at https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf.
[133] *See* Air Individual Permit No. 13700028-103, Virginia Department of Public Utilities, August 6, 2021, at 5.
[134] *Id.*
[135] August 2022 Draft Minnesota Regional Haze Plan at 82-83.

MPCA identified the emissions from the Virginia Department of Public Utilities as follows:

Table 18. Virginia Department of Public Utilities 2016 Emissions Data Used in Q/d Analysis[136]

NH3, tons/year	NOx, tons/year	PM2.5, tons/year	SO2, tons/year	VOC, tons/year	Total, tons/year
42.33	346.09	20.88	300.73	13.00	723.03

MPCA states that Boiler #9, which is not listed in the most recent permit description, retired permanently in 2021.[137] MPCA's draft regional haze plan indicates that it requested a four-factor analysis of NOx and SO2 controls for Boiler #7 and of SCR for NOx control at Boiler #11.[138] MPCA also states that Boiler #7 has proposed retirement by January 2027, and MPCA has included an Administrative Order in the Minnesota Regional Haze Plant that requires Boiler #7 to be retired no later than January 1, 2025.[139]

MPCA identified the NOx emission data for Boiler #11 as follows:

Table 19. Annual NOx Emissions Data for VDPU Boiler #11[140]

	2016	2017	2018	2019	2020	4-Factor Analysis Baseline
Boiler #11	103.45	82.94	42.03	38.05	74.90	103.44

VDPU submitted a four-factor analysis for Boiler #11. This wood- and natural gas-fired boiler is equipped with SNCR for NOx control and a multiclone followed by an electrostatic precipitator (ESP) for PM control. MPCA found that SCR was not cost effective for Boiler #11.[141] In its four-factor analysis, VDPU states that Boiler #11 will "most likely burn only natural gas moving forward," despite the boiler being capable of co-firing wood and natural gas.[142] VDPU's four-factor analysis also showed widely varying actual NOx emission rates for the boiler, ranging from 0.094 lb/MMBtu to 0.175 lb/MMBtu.[143] MPCA should evaluate and disclose the NOx emission rates that correspond to burning only natural gas in Boiler #11. If NOx emission rates are projected to increase with the boiler no longer burning wood in the future, then that increase in emissions should be taken into account into the evaluation of SCR for NOx control. In addition, VDPU did not evaluate low NOx burners as a NOx control measure, because it stated Boiler #11 is primarily a wood-fired boiler.[144] However, if the boiler will be only operating on natural gas in the future, then installation of low NOx burners is a technically feasible NOx control that should be evaluated in a four-factor analysis. Thus, MPCA must evaluate controls for Boiler #11

[136] August 2022 Draft Minnesota Regional Haze Plan at 49 (Table 28).
[137] *Id.* at 57.
[138] *Id.* at 90.
[139] August 16, 2022 MPCA Administrative Order by Consent In the Matter of: Virginia Department of Public Utilities, in Appendix D of August 2022 Draft Minnesota Regional Haze Plan.
[140] *Id.* at 92-93.
[141] CITE
[142] June 4, 2021 Virginia Department of Public Utilities Four-Factor Analysis at 2, August 2022 Draft Minnesota Regional Haze Plan, Appendix B.
[143] *Id.* at 3.
[144] *Id.* at 6.

reflective of the unit firing only natural gas, as VDPU indicated would be its future operations, to determine appropriate NOx controls and emission limits for the boiler.

There are three other boilers at VDPU's facility: Boilers #10, #12, and #13. MPCA did not explain or justify why it did not require four-factor analyses of controls for these boilers. VDPU states that Boilers #12 and #13, which are either newly installed or soon to be installed, "will become the main boilers for serving the district heating system."[145] These boilers appear to have been permitted as minor modifications and presumably were exempt from a best available control technology (BACT) determination.[146] Given how VDPU plans to operate these as the main boilers in the future, MPCA should ensure that these boilers are evaluated for regional haze controls in a four-factor analysis. MPCA should also evaluate Boiler #10 for regional haze controls.

VI. Hibbing Public Utilities Commission

Hibbing Public Utilities Commission (HPUC) operates a cogeneration plant located in Hibbing, Minnesota consisting of four boilers to generate steam and electricity. The facility has the ability to generate electricity and steam, but currently the facility is not generating electricity and is solely providing steam to a steam distribution system for space heating, nearby business for industrial purposes, schools, and residences. Boilers 1A, 2A, and 3A currently burn primarily coal and Boiler 7 is primarily a wood-fired boiler. The wood-fired boiler also has the ability to co-fire natural gas, and that boiler is equipped with SNCR and a multiclone followed by an ESP.[147] Boilers 1A, 2A, and 3A are permitted to burn coal, natural gas, used oil, and oily cellulose-based sorbents (including rags). These units do not have any NOx or SO2 pollution controls. MPCA calculated a Q/d value for this plant of 7.47 for the Boundary Waters Class I area and of 8.33 for the Voyageurs National Park Class I area.[148]

MPCA identified the emissions from the Hibbing Public Utilities Commission as follows:

Table 20. Hibbing Public Utilities Commission 2016 Emissions Data Used in Q/d Analysis[149]

NH3, tons/year	NOx, tons/year	PM2.5, tons/year	SO2, tons/year	VOC, tons/year	Total, tons/year
41.33	477.95	12.34	369.47	12.44	913.53

MPCA's draft regional haze plan indicates that it requested a four-factor analysis of NOx and SO2 controls for Boilers 1A, 2A, and 3A and of NOx controls for the wood-fired boiler.[150] MPCA identified the following emissions data for these emission units. The table below also provides the assumed emissions for the 2028 modeling and the development of RPGs.

[145] *Id.* at 3.
[146] *See* https://www.pca.state.mn.us/sites/default/files/Public-%20Notice%20-%2013700028-102%20-%202021.pdf.
[147] July 28, 2020 HBUC Four-Factor Analysis at 2, in August 2022 Minnesota Regional Haze Plan, Appendix B.
[148] August 2022 Draft Minnesota Regional Haze Plan at 53-54.
[149] August 2022 Draft Minnesota Regional Haze Plan at 49 (Table 28).
[150] *Id.* at 89.

Table 22. Hibbing Public Utilities Commission 2016-2020 Emissions Data, Baseline Used for Four-Factor Analysis, and Emissions Modeled for 2028[151]

	2016	2017	2018	2019	2020	Baseline for Four-Factor Analysis	Emissions assumed for 2028 Modeling
NOx Emissions Data, tons per year							
Boiler 1A	157.81	118.87	111.75	43.21	23.65	111.75	164.51
Boiler 2A	39.50	1.09	0.00	0.00	0.00	111.75	164.52
Boiler 3A	193.6	167.14	133.27	82.20	81.70	133.27	164.51
Wood-fired Boiler	87.05	86.76	31.95	15.24	10.67	31.95	87.29
SO2 Emissions Data, tons per year							
Boiler 1A	149.1	181.70	83.08	3.29	3.25	108.73	347.97
Boiler 2A	37.33	1.23	-	-	-	108.73	347.97
Boiler 3A	168.32	158.04	78.65	36.18	36.18	104.93	347.97

HPUC initially evaluated controls for the boilers in a four-factor analysis, and MPCA revised the HPUC's cost effectiveness analyses and showed that SNCR would be a cost-effective NOx control for Boiler 1A, 2A, and 3A at costs ranging from $6,004/ton - $6,592/ton.[152] MPCA states that its "initial recommendation" was to require the facility to install SNCR at Boilers 1A, 2A, and 3A, but then the company presented a "revised operations plan" referred to as the "Hibbing Public Utilities Restorative Plan," which the Hibbing Public Utilities Commission adopted in May of 2022.[153] This plan indicates the Commission's intent to primarily use wood and natural gas as fuels at HPUC and to use coal as a backup/emergency fuel. The HPUC plan states that coal was identified as a backup fuel so that the Commission would have "all options available to it to better protect its customers from global supply shock of natural gas price fluctuations and power grid volatility."[154] The plan also states that that this plan "will allow the HPUC to keep the ability to burn coal in its air permit and avoid costly pollution control equipment for a fuel source that is not a planned baseload fuel."[155]

Based on this "Restorative Plan," MPCA adopted an Administrative Order that limits the combined NOx emissions from Boiler 1A and Boiler 2A to 134 tons per 12-month rolling sum and that limits NOx emissions from Boiler 3A to 80 tons per 12-month rolling sum.[156] MPCA explains its justification for these mass-based emission limits instead of requiring SNCR and adopting appropriate rate-based (lb/MMBtu) NOx limits as follows:

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[151] *Id.* at 92-94.
[152] *Id.* at 97.
[153] *Id.* at 107-108.
[154] May 24, 2022 Hibbing Public Utilities Commission Restorative Utility Plan at 1, in August 2022 Draft Minnesota Regional Haze Plan, Appendix B at pdf page 406.
[155] *Id.*
[156] 8/19/2022 MPCA Administrative Order, In the Matter of Hibbing Renewable Energy Center, at 3, in August 2022 Minnesota Regional Haze Plan, Appendix D at pdf page 4.

> Based on the additional information provided by the facility, NOx controls remain cost effective for the facility in this regional haze implementation period. However, instead of installing potential controls, the facility accepted limits on NOx emissions for the boilers that resulted in equivalent reductions that would have been achieved with installing SNCR on each boiler.[157]

It must first be noted that MPCA's Administrative Order does not include adequate requirements as to how compliance with the NOx tons per rolling 12-month limits will be demonstrated. It does not appear that Boilers 1A, 2A, or 3A have continuous emissions monitoring systems (CEMs) for NOx. HPUC's four-factor analysis only provided NOx CEMs data for the wood-fired boiler (Boiler 7). While the Administrative Order requires the type and amount of each fuel combusted in each boiler be calculated and recorded, the Order does not state how the corresponding actual NOx emission rates (in terms of pounds NOx per MMBtu or pounds NOx per quantity of fuel used) are to be determined. Specifically, the compliance provisions of the Order states that HPUC must calculate and record the following:

- The type and amount of each fuel combusted in each individual boiler (Boiler 1A, Boiler 2A, and Boiler 3A) during the previous month.
- The NOx emissions for each individual boiler (Boiler 1A, Boiler 2A, and Boiler 3A) for the previous month by using the type and amount of each fuel combusted to calculate NOx emissions from each fuel combusted.
- The 12-month rolling sum of NOx emissions for the limits described in Order Paragraphs 1 and 2, and for the previous 12-month period by summing the monthly NOx emissions data for the previous 12 months.[158]

Without CEMs for NOx, the Administrative Order NOx limits are unenforceable because the Order fails to specify NOx testing and test methods for assessing actual NOx emission rates.

Although MPCA has not stated as such, it appears that the State may have determined that mass-based, long term emission limits could be imposed in lieu of requiring SNCR installation because of the HPUC Restorative Plan's statement that coal would be used as a backup fuel. However, the Restorative Plan does not prohibit coal from being used in Boilers 1A, 2A, or 3A. MPCA did state that Boiler 2A "is not currently able to combust coal without additional maintenance, which HPU is not pursuing at this time."[159] HPUC stated in a supplement to its four-factor analysis that it was "embarking on [a] pilot season of burning biomass fuel for the 2021/2022 heating season for the purpose of gather[ing] more data and optimizing sustainability options for future growth."[160] MPCA should explain if the pilot seasons for burning biomass are the reason why MPCA claims Boiler 2A is currently not able to combust coal without additional maintenance. HPUC has not stated that Boiler 1A or Boiler 3A cannot burn coal at any time.

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[157] August 2022 Draft Minnesota Regional Haze Plan at 108.
[158] 8/19/2022 MPCA Administrative Order, In the Matter of Hibbing Renewable Energy Center, Order ¶ 4, in August 2022 Minnesota Regional Haze Plan, Appendix D at pdf page pdf 4.
[159] August 2022 Draft Minnesota Regional Haze Plan at 108.
[160] June 18, 2021 HBUC Four-Factor Analysis and Response to Comments of 4-Factor Analysis for Hibbing Public Utilities at 2, in August 2022 Minnesota Regional Haze Plan, Appendix B.

It is notable that MPCA has not proposed any reduction in SO2 emission limits, or even any tons per 12-month rolling limits, for Boilers 1A, 2A, or 3A, and that HPUC has refuted the need for lower SO2 emission limits. Specifically, the National Park Service commented that the boilers each have allowable SO2 emission limits that are much higher than actual SO2 emission rates. Specifically, the boilers have allowable SO2 limits of 4.0 lb/MMBtu, which is a very high uncontrolled SO2 limit. The National Park Service recommended reducing the boilers' SO2 limits to be closer to the units' actual SO2 emission rates of 0.30 lb/MMBtu to prevent backsliding.[161] Yet, HPUC refuted the need for lower SO2 limits, claiming that pound per hour SO2 limits in the HPUC permit "equated" to 0.90 lb/MMBtu SO2 limits.[162] However, one cannot equate the boilers' mass-based, pound per hour SO2 limits to 0.90 lb/MMBtu SO2 emission limits because the mass-based limits would only limit SO2 emission lb/MMBtu rates when the boilers operate at maximum heat input capacity. A pound per million Btu limit, on the other hand, would limit SO2 emissions over all levels of operating capacity. Second, even if there was an effective "limit" on SO2 of 0.90 lb/MMBtu for the boilers, that is still three times higher than the boilers' current SO2 emission rates of 0.30 lb/MMBtu. Moreover, HPUC's unwillingness to take a reduced SO2 limit does not lend confidence to HPUC's plan to limit coal use to only as a backup fuel. It would appear that HPUC wants the flexibility to burn coal and to burn a much higher sulfur coal than currently used.

As previously stated, the Administrative Order states that the currently allowable fuels for Boilers 1A, 2A, and 3A are coal, used oil, natural gas, and oily cellulose-based sorbents (including rags) as identified in the facility's Air Emissions Permit No. 13700027-102. While HPUC states its intent to use coal only as a backup fuel in the future, there is no enforceable prohibition on coal use. It seems likely that fuel blends of varying quantities could be used at these boilers. Given that the precise fuels to be used in Boilers 1A, 2A, and 3A are unknown and unclear, the lb/MMBtu NOx emission rates could vary widely with the fuel types and with fuel blends. Thus, even if the Administrative Order was modified required NOx stack testing, it would need to be frequent stack testing sufficient to capture any variability in NOx emission rates to accurately assess compliance with the mass-based 12-month rolling emission limits.

Without MPCA imposing limits on SO2 emissions or on coal use, and with the 12-month rolling NOx mass limits not being enforceable due to the lack of CEMs and the lack of testing requirements for establishing actual NOx emission rates, MPCA has not justified its decision to adopt 12-month mass NOx emission limits rather than require installation of the SNCR NOx control that it found to be cost-effective for the three boilers in a four-factor analysis of controls. EPA recommends that "a state that has determined that a technology-based measure is necessary for reasonable progress initially consider emission limits expressed in terms of pounds per throughput (i.e., input or output) based on the capability of that [control] measure."[163] While EPA states that the regional haze rule "allows SIPs to contain limits on mass emissions during a particular time period (*e.g.*, a cap on 30-operating day mass emissions)," EPA also states that "[a] mass-based emission limit could allow a source that sufficiently reduces its operating level to cease operating the emission controls equipment that the state had

[161] July 11, 2022 Comments from the National Park Service to MPCA at 4, in August 2022 Draft Minnesota Regional Haze Plan, Appendix G at pdf page 7.
[162] June 18, 2021 HBUC Four-Factor Analysis and Response to Comments of 4-Factor Analysis for Hibbing Public Utilities at 4, in August 2022 Minnesota Regional Haze Plan, Appendix B. For example, HBUC stated that the Boiler 1 SO2 limit of 194.40 lb/hr equated to an SO2 limit of 0.90 lb/MMBtu when the boiler was operated at maximum rated capacity (i.e., 194.40 lb/hr / 216 MMBtu/hr = 0.9 lb/MMBtu).
[163] 8/20/2019 EPA guidance at 44.

determined to be reasonable."[164] EPA further indicates that, if the state has determined that the operation of emission control equipment is necessary to make reasonable progress, "a mass-based emission limit may not be appropriate."[165]

A technology-based reasonable progress requirement including imposition of lb/MMBtu limits will ensure that NOx is reduced from current levels on a continuous basis from Boilers 1, 2, and 3. MPCA's NOx per 12-month emission limits would not ensure NOx is reduced on a continuous basis from the HPUC boilers without also requiring installation and operation of SNCR. Further, if these boilers may be operated more on a seasonal basis rather than continually throughout the year, the rolling 12-month limits could allow NOx emissions to increase on a daily basis during the operating seasons and exacerbate regional haze on those days. If mass-based emission limits could be justified by MPCA, the limits should apply on a much shorter timeframe. In referencing mass-based emission limits during a particular timeframe, EPA gives the example of a "cap on 30-operating day mass emissions."[166] Given that EPA has historically allowed regional haze emission limits to apply over a 30- day averaging period,[167] any mass-based limit justified by MPCA should not apply over an averaging period longer than 30-days. In addition, to accurately ensure compliance with the any mass-based limits, MPCA must impose a requirement for NOx CEMs to be installed and operated at each boiler to accurately monitor NOx emissions

In summary, MPCA's NOx limits of its Administrative Order for HPUC fail to assure reasonable progress due to being unenforceable and due to applying over too long of a time period. Further, the emission limits do not reflect the NOx removal capabilities of the SNCR control that MPCA found to be cost-effective for Boilers 1A, 2A, and 3A via a four-factor analysis of controls. MPCA has not justified the 12-month rolling mass-based NOx emission limits as reasonable progress measures under the regional haze program.

[164] *Id.*
[165] *Id.* at 45.
[166] *Id.* at 44.
[167] *See* 40 C.F.R. Part 51, Appendix Y, Section V.