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]

---

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

---

[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

---

[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

[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]

---

[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]

---

[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]

---

[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.

---

[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):

---

[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

---

[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

---

[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.

---

[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

---

[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.

---

[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

---

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,

Michael B. Murray
Chair
Coalition to Protect America's National Parks
2 Massachusetts Ave NE
Unit 77436
Washington, DC 20013
Editor@protectnps.org

Ann Jaworski
Staff Attorney
Environmental Law & Policy Center
35 East Wacker Drive, Suite 1600
Chicago, IL 60601
AJaworski@elpc.org

Evan Mulholland
Healthy Communities Program Director
Minnesota Center for Environmental Advocacy
1919 University Avenue, Suite 515
St. Paul, MN 55104
emulholland@mncenter.org

Christine Goepfert
Midwest Campaign Director
National Parks Conservation Association
2636 Lyndale Avenue South
Minneapolis, MN 55408
cgoepfert@npca.org

Kristin Henry
Managing Attorney
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
kristin.henry@sierraclub.org

Sara L. Laumann
Principal
Laumann Legal, LLC.
3800 Buchtel Blvd. S. #100236
Denver, CO 80210
sara@laumannlegal.com
Counsel for National Parks Conservation Association

cc:

Debra Shore, Regional Administrator, EPA Region 5, Shore.Debra@epa.gov

John Mooney, Division Director, Air and Radiation Division, EPA Region 5, Mooney.John@epa.gov

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]

---

[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

---

[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:

<u>Taconite Processing Plants</u>

- 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 (NH3), NOx, PM2.5, SO2, 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 NH3, NOx, PM2.5, SO2, 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]

---

[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

---

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.

---

[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

[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

---

[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.

---

[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.

---

[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

[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.

---

[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]

---

[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:

---

[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.

---

[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]

---

[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:

---

[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.

---

[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.