Regional Haze

August 2022

Minnesota’s State Implementation Plan for Regional Haze

Comprehensive update for the second implementation period (2018 - 2028)

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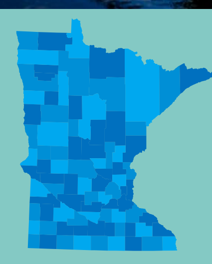

Authors

Hassan Bouchareb, MPCA

Margaret McCourtney, MPCA

Maggie Wenger, MPCA

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Cover Image - Sawbill Lake, Boundary Waters Canoe Area Wilderness

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Executive Summary

The state of Minnesota is home to two mandatory Class I Federal areas (Class I areas), the Boundary Waters Canoe Area Wilderness (Boundary Waters) and Voyageurs National Park (Voyageurs), located along the state's border with Canada. In compliance with the Regional Haze Rule, the Minnesota Pollution Control Agency (MPCA) is submitting to the U.S. Environmental Protection Agency (U.S. EPA) this comprehensive update to Minnesota's Regional Haze State Implementation Plan (SIP) to meet the goal of restoring Class I areas to natural visibility conditions by 2064.

Minnesota's Regional Haze SIP for the second implementation period outlines significant improvements in visibility at Boundary Waters and Voyageurs, identifies additional emission reduction opportunities, examines the uniform rate of progress projected to 2064, and sets reasonable progress goals for 2028. This document also serves as a progress update for 2015-2021.

Visibility trends. Visibility continues to improve at Boundary Waters and Voyageurs. Minnesota continues to demonstrate that there is no degradation on the clearest days at Boundary Waters and Voyageurs. For the most impaired days, Boundary Waters improved from 18.5 deciviews in 2004 to 13.4 deciviews in 2019. Voyageurs improved from 17.9 deciviews in 2004 to 13.5 deciviews in 2019. These levels are below the glidepath for reaching natural visibility conditions by 2064.

The main pollutants contributing to visibility impairment in Minnesota's Class I areas are ammonium sulfate and ammonium nitrate. The main states whose emissions contribute to visibility impairment in Boundary Waters and Voyageurs are Minnesota, North Dakota, Iowa, Nebraska, Wisconsin, and Missouri.

Geographic and sector contribution analysis. MPCA also assessed the contributions to visibility impairment, by geographic region and sector grouping, from Minnesota, North Dakota, Iowa, Nebraska, Wisconsin, and Missouri. From this analysis, MPCA concludes that Minnesota continues to be the largest state contributor to visibility impairment at Boundary Waters and Voyageurs, additional nitrogen oxide (NO_X) emission reductions are needed, and Boundary Waters and Voyageurs may benefit from emission reductions in other regions or states located to the West and Northwest but also from other directions, in the following order of importance: Canada, North Dakota, Iowa, Nebraska, Wisconsin, and Missouri.

Furthermore, MPCA adds that sulfur dioxide (SO_2) emission reductions from electric generating units (EGUs) in other states may likely lessen visibility impacts at Boundary Waters and Voyageurs as well. North Dakota, Iowa, Nebraska, and Missouri contribute most to visibility impairment from EGU sector emissions. Minnesota and Wisconsin's top two sector contributors to visibility impairment, in order of importance, are industry and vehicle emissions.

Emission trends and reasonable progress goals. Minnesota has achieved significant NO_X and SO_2 reductions since the first regional haze implementation period, primarily driven by coal-fired electricity generating unit retirements, through today. From 2002 to the end of the first implementation period in 2018, Minnesota saw a 59% reduction in NO_X emissions and a 79% reduction in SO_2 emissions from stationary sources. Emissions data through 2020 indicates that Minnesota stationary sources have reduced NO_X emissions by 71% and SO_2 emissions by 89% since 2002.

Based on the emissions projected for 2028, Minnesota has established the 2028 reasonable progress goals for the second implementation period at 13.4 deciviews for Boundary Waters and 13.6 deciviews for Voyageurs.

Four-factor analysis source selection thresholds. 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. This top 85% threshold represented those facilities that had a Q/d value of roughly 4.6. MPCA requested that these sources prepare and submit a four-factor analysis as part of preparing this SIP submittal. These sources included emission units at taconite processing facilities, pulp/paper mills, sugar manufacturing facilities, and electric power generation facilities.

Four-factor analysis cost evaluation thresholds. To evaluate the cost of compliance, MPCA requested that each facility prepare cost estimates for the potential control measures evaluated in the four-factor analysis. MPCA evaluated the cost to implement the analyzed control measures to determine what control measures were generally cost-effective. MPCA did not use a specific threshold to uniformly determine whether a control measure was cost-effective, but MPCA used an initial screening threshold of roughly $10,000 per ton to determine which control measures to focus on. Control measures that cost more than $10,000 per ton were determined to be likely not cost-effective in this implementation period. Ultimately, the controls that MPCA identified as potentially cost-effective for this regional haze implementation period cost less than approximately $7,600 per ton of pollutant reduced.

Proposed emission control measures. In this implementation period, the MPCA chose to focus on reducing emissions of NO_X and SO_2 because they lead to the formation of ammonium nitrate and ammonium sulfate, the particulate species that contribute most to regional haze at Boundary Waters and Voyageurs. Minnesota has included the effects of planned retirements for coal-fired combustion units and the Taconite Federal Implementation Plan (FIP) requirements in this implementation period. Minnesota's long-term strategy also includes new emission reduction targets (30% by 2025 and 40% by 2028, relative to a 2018 baseline) for point sources in Northeastern Minnesota that emit over 100 tons per year of either NO_X or SO_2.

Minnesota also identified cost-effective control technologies including selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) at smaller electric utilities and industrial boilers. Some facilities chose to retire equipment earlier to avoid installing controls. All emission reductions identified in this SIP submittal are recorded in enforceable permit actions or administrative orders.

Long-term strategy summary. Minnesota has met the requirements of the Regional Haze Rule to develop this comprehensive update to Minnesota's long-term strategy. MPCA evaluated and determined the emission reduction measures needed to make reasonable progress and documented the methodology used in this SIP submittal. The emission reduction measures include completed/upcoming emission unit retirements, utilization of existing effective controls, additional expected reductions that will be achieved from other programs, and the creation of new, non-binding emission reduction targets in the Northeast Minnesota Plan.

During subsequent regional haze implementation periods, Minnesota will continue to evaluate reasonable emission reductions and expects contributing states to do the same.

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Acronyms and Abbreviations

Acronym/Abbreviation	Description
µm	Micrometers
40 CFR Part 51	Code of Federal Regulations, title 40, Part 51
40 CFR Part 52	Code of Federal Regulations, title 40, Part 52
40 CFR Part 63	Code of Federal Regulations, title 40, Part 63
40 CFR Part 87	Code of Federal Regulations, title 40, Part 87
AO	Administrative Order
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
B_{ext}	Light extinction coefficient, called beta extinction, expressed in units of inverse megameters (Mm^{-1})
BLS	Black liquor solids
Boundary Waters	Boundary Waters Canoe Area Wilderness
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMD	Clean Air Markets Division
CAMx	Comprehensive Air quality Model with eXtensions
CEMS	Continuous Emission Monitoring System
CENRAP	Central Regional Air Planning Association
CENSARA	Central States Air Resource Agencies
CFR	Code of Federal Regulations
chapter 7011	Minnesota Rules chapter 7011
chapter 7019	Minnesota Rules chapter 7019
CIRA	Cooperative Institute for Research in the Atmosphere
CMAQ	Community Multiscale Air Quality
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CSAPR	Cross-State Air Pollution Rule
CSN	Continuous Speciated Network
DSI	Dry sorbent injection
EC	Elemental carbon
EGU	Electric generating unit
ERTAC	Eastern Regional Technical Advisory Committee
FGD	Flue gas desulfurization
FGR	Flue gas recirculation
FIP	Federal Implementation Plan
FLMs	Federal Land Managers

Acronym/Abbreviation	Description
gr	Grains
HAP	Hazardous air pollutant
IMPROVE	Interagency Monitoring of Protected Visual Environments
LADCO	Lake Michigan Air Directors Consortium
LAER	Lowest Achievable Emission Rate
lb/MMBtu	Pounds per million British thermal units
LNB	Low NO_X burners
LTS	Long-term strategy
LVHC	Low volume high concentration
m^3	Cubic meter
MATS	Mercury and Air Toxics Standards Rule
mg	Milligram
Minn. R.	Minnesota Rules
Minn. R. ch.	Minnesota Rules chapter
Minn. Stat. ch. or §	Minnesota Statutes chapter or section
Mm^{-1}	Inverse megameters
MNTEC	Minnesota Tribal Environmental Council
MPCA or Agency	Minnesota Pollution Control Agency
MRPO	Midwest Regional Planning Organization
NAAQS	National Ambient Air Quality Standards
NCG	Non-condensable gas
NEI	U.S. EPA's National Emission Inventory
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
NH_4NO_3	Ammonium nitrate
NH_4SO_4	Ammonium sulfate
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
OCM	Organic carbon mass
OFA	Overfire air
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers, or fine PM
PSAT	Particulate Source Apportionment Technology
PSD	Prevention of Significant Deterioration
psia	Pounds per square inch (absolute)
RACT	Reasonably Available Control Technology
RAVI	Reasonably Attributable Visibility Impairment

Acronym/Abbreviation	Description
RBLC	U.S. EPA's RACT/BACT/LAER Clearinghouse
RFI	Request for information
RPG	Reasonable progress goal
RPO	Regional Planning Organization
RRF	Relative Response Factors
scf	Standard cubic foot
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
tpy	Tons per year
TSD	Technical Support Document
U.S. DA	United States Department of Agriculture
U.S. DI	United States Department of Interior
U.S. EPA	United States Environmental Protection Agency
U.S. FS	United States Forest Service
U.S. FWS	United States Fish and Wildlife Service
U.S. NPS	United States National Park Service
URP	Uniform Rate of Progress
U.S.C.	United States Code or U.S. Code
VOC	Volatile organic compound
Voyageurs	Voyageurs National Park
WRAP	Western Regional Air Partnership

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1. Regional Haze program overview

1.1. Background Information

In amendments to the Clean Air Act (CAA) in 1977, Congress added Section 169A, establishing a national visibility goal of restoring natural visibility conditions in many national parks and wilderness areas.[1] These areas were designated as mandatory Class I federal areas (Class I areas). Class I areas are composed of all international parks in the United States, all national wilderness areas and memorial parks larger than 5,000 acres, and all national parks larger than 6,000 acres in size that were in existence by 1977.[2]

Class I areas have the smallest increments of additional pollutants allowed out of the three Classes of areas under the Prevention of Significant Deterioration (PSD) provisions.[3] The purpose of the PSD provisions is "to preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value".[4] In the Class I areas, visibility was identified as an important value.[5] Section 169 states, "Congress hereby declares as a national goal the prevention of any future, and the remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution."[6]

To achieve the national visibility goals mandated by Congress, in 1999 the U.S. Environmental Protection Agency (U.S. EPA) established a regulatory program called the Regional Haze Rule (40 CFR § 51.308) under the Clean Air Act.[7] This program created regulations designed to improve visibility in national parks and wildernesses designated as Class I areas across the United States and restore them to natural visibility conditions by 2064. The Regional Haze Rule is found in 40 CFR Part 51, Subpart P and covers 156 Class I areas in the United States. Minnesota is home to two Class I areas, the Boundary Waters Canoe Area Wilderness (Boundary Waters) and Voyageurs National Park (Voyageurs), located along the state's border with Canada.

The regional haze program addresses the combined visibility effects of various pollution sources over a wide geographic region, meaning that even states without Class I areas are required to participate in haze reduction efforts. States are responsible for developing a Regional Haze State Implementation Plan (SIP) that addresses regional haze in each Class I area located within the state and in each Class I area located outside the state which may be affected by emissions from sources within the state.

The overall purpose of the regional haze program is to identify existing sources that cause or contribute to visibility impairment; analyze, identify, and apply federally-enforceable control strategies for those sources; and periodically demonstrate reasonable progress toward reaching visibility goals. In each Regional Haze SIP, states must set goals reflecting reasonable pollution controls and emission reductions and the resulting visibility improvement achieved by the controls in the specified timeframe. States are

[1] *See* 42 U.S.C. § 7491.
[2] *See Clean Air Act § 162, 42 U.S.C. § 7472(a); 40 CFR § 52.21(e).*
[3] *See 40 CFR § 51.166(c); 40 CFR § 52.21(c);* Prevention of Significant Deterioration New Sources Review: Refinement of Increment Modeling Procedures, *72 Fed. Reg. 31374 (June 6, 2007).*
[4] *See CAA § 160, 42 U.S.C. § 7470(2).*
[5] *See* 40 CFR § 81.400; National Visibility Goal for Class I Areas; Identification of Mandatory Class I Federal Areas Where Visibility is an Important Value, *44 Fed. Reg. 69122 (Nov. 30, 1979).*
[6] 42 U.S.C. § 7491(a)(1)
[7] *See* Regional Haze Regulations, 64 Fed. Reg. 35714 (July 1, 1999); Protection of Visibility: Amendments to Requirements for State Plans, 82 Fed. Reg. 3078 (Jan. 10, 2017).

also responsible for periodic comprehensive updates to their Regional Haze SIPs that address these same topics. States were required to submit their first Regional Haze SIP to U.S. EPA by December 17, 2007.[8] States must revise and submit their Regional Haze SIP revisions to the U.S. EPA by July 31, 2021, July 31, 2028, and every 10 years thereafter.[9]

In between comprehensive updates, states are responsible for providing interim progress reports that outline the status of required Regional Haze SIP elements. The progress reports evaluate how the state is moving towards the visibility goals for each Class I area to assess whether changes to the state's Regional Haze SIP are needed to achieve these goals. States were required to submit their first periodic progress report to U.S. EPA five years from the submittal of their first Regional Haze SIP.[10] States are required to provide subsequent periodic progress reports to U.S. EPA by January 31, 2025, July 31, 2033, and every 10 years thereafter.[11]

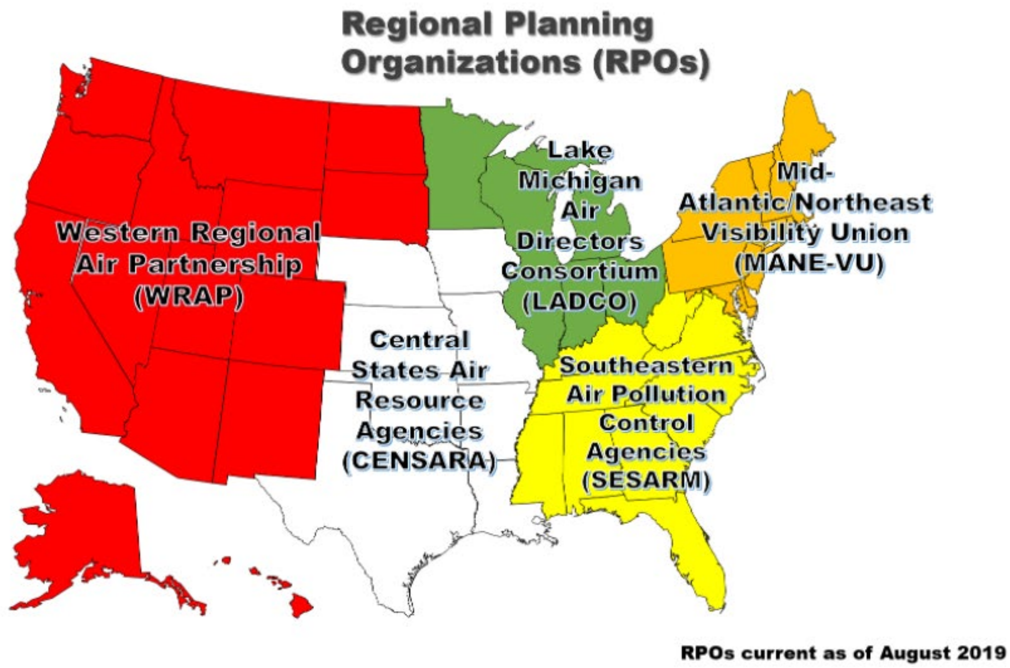
The U.S. EPA has encouraged states to collaborate when developing the technical information needed to better understand the causes of visibility impacts in the Class I areas and the measures needed to mitigate visibility impacts. States have grouped into five Regional Planning Organizations (RPOs) to address visibility. In the first implementation period, Minnesota joined the Central Regional Air Planning Association (CENRAP) RPO, which was affiliated with the Central States Air Resource Agencies (CENSARA) Multi-Jurisdictional Organization (MJO).

It soon became evident that the Minnesota and Michigan Class I areas are in the same airshed, due to the proximity of the Class I areas and the highly correlated $PM_{2.5}$ chemical species observed at monitors among these Class I areas. In June 2004, CENRAP and the MidWest RPO, of which Michigan was a member, came to an agreement that MidWest RPO would take the lead in compiling emissions inventories and developing the photochemical modeling framework for the entire airshed.

Following the first implementation period, the RPO names reverted to the MJO names. The MJOs address other regional air issues in addition to haze. Minnesota officially joined the Lake Michigan Air Directors Consortium (LADCO) MJO. The LADCO member states include Minnesota, Wisconsin, Illinois, Indiana, Michigan, and Ohio.

[8] *See* 40 CFR § 51.308(b).
[9] *See* 40 CFR § 51.308(f).
[10] *See* 40 CFR § 51.308(g).
[11] *See id.*

Figure 1. Regional Planning Organizations/Multi-Jurisdictional Organizations[12]



1.2. Minnesota's Regional Haze SIP (first implementation period)

To meet the core requirements for regional haze, Minnesota had to submit a SIP that contained the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(d) and 40 CFR § 51.308(e).

The MPCA submitted its initial SIP addressing the requirements of the Regional Haze Rule to U.S. EPA on December 31, 2009. The 2009 Regional Haze SIP identified visibility conditions, set 2018 visibility goals ("Reasonable Progress Goals," or RPG) for Minnesota's Class I areas (Boundary Waters and Voyageurs), and determined that Minnesota may contribute to visibility impairment at Isle Royale National Park in Michigan. The SIP also outlined control strategies intended to support making progress towards visibility goals in Class I areas affected by Minnesota's emissions. Minnesota developed its SIP with extensive consultation with stakeholders, including FLMs, Tribal representatives, industry representatives, CENRAP, LADCO/MRPO, individual states, and the Ontario Ministry of the Environment.

The focus of the Regional Haze Rule in the first implementation period was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress goals towards national visibility goals. The SIP had to determine BART and schedules for compliance with BART for each subject-to-BART source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Federal Class I area. The state also had an option to demonstrate that an emissions trading program or other alternative would achieve greater reasonable progress toward natural visibility conditions than would be achieved through the installation and operation of BART.

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[12] U.S. EPA, VISIBILITY - REGIONAL PLANNING ORGANIZATIONS, *https://www.epa.gov/visibility/visibility-regional-planning-organizations* (last visited June 6, 2022).

In order to identify BART-eligible units, the MPCA used the following criteria:

1. One, or more, emission(s) units at the facility fit within one of the twenty-six (26) categories listed in 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations Under the Regional Haze Rules;
2. The emission unit(s) were in existence on August 7, 1977 and began operation at some point on or after August 7, 1962; and
3. The sum of the potential emissions from all emission unit(s) identified in the previous two bullets was greater than 250 tons per year of the visibility-impairing pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter less than 10 microns (PM_{10}).

After identifying the BART-eligible units, the MPCA chose to evaluate which BART-eligible units became subject-to-BART through an individual source attribution approach to determine which sources caused or contributed to visibility impairment. Modeling was conducted in accordance with the 40 CFR Part 51, Appendix Y Guidelines. BART-eligible units became subject-to-BART when the results of the modeling analysis showed the BART-eligible source contributed to visibility impairment on 21 or more days over a three-year period with a 98% percentile change in visibility greater than or equal to 0.5 deciviews. Subject-to-BART units were required to conduct a BART analysis.

The determination of BART is based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each subject-to-BART source. This analysis considers the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[13]

In addition to BART, Minnesota's SIP analysis indicated that the main pollutants contributing to visibility impairment in Minnesota's Class I areas are ammonium sulfate (sulfate), ammonium nitrate (nitrate), and organic carbon. Modeling indicated that the organic carbon is biogenic, so the MPCA chose to focus control measures on the anthropogenic emissions of NO_X and SO_2 that lead to formation of nitrate and sulfate. The main contributors of SO_2 emissions were electric generating units (EGUs), while the main contributors of NO_X were motor vehicles, both on and off road. The main states whose emissions contributed to visibility impairment in Boundary Waters and Voyageurs are Minnesota, Wisconsin, Illinois, Iowa, Missouri, and North Dakota.

Minnesota's multi-prong long-term strategy included the implementation of several federal programs in Minnesota and surrounding states and set a target for a 30% reduction in combined nitrogen dioxide (NO_X) and sulfur dioxide (SO_2) emissions by 2018 from permitted sources in Northeastern Minnesota that emit over 100 tons per year of either NO_X or SO_2. Data from 2018 shows a combined NO_X and SO_2 reduction of roughly 55% from the 2002 base year, largely due to reductions from the utility sector.

MPCA supplemented its Regional Haze SIP in 2012, updating its BART strategies for both power plants and the taconite industry, as well as its long-term strategy focused on the taconite industry. The U.S. EPA approved nearly all elements of Minnesota's Regional Haze SIP, effective July 12, 2012, deferring action on Minnesota's BART determinations for the taconite industry and one electric utility. U.S. EPA subsequently promulgated FIPs that incorporated revised BART determinations for taconite facilities and the electric utility.

[13] *See* 40 CFR Part 51, Appendix Y.

1.3. U.S. EPA's Regional Haze Federal Implementation Plan (FIP) for taconite facilities

In the MPCA's 2009 Regional Haze SIP and subsequent 2012 SIP supplement, the MPCA identified site specific NO_X and SO_2 BART determinations for emission sources at taconite facilities. In general, the MPCA determined for all taconite pellet furnaces that:

- BART for NO_X emissions was an operating standard of good combustion practices in combination with other process changes to reduce NO_X emissions and improve fuel efficiency.
- BART for PM emissions was equivalent to the requirements of 40 CFR Part 63, Subpart RRRRR that requires control of PM emissions to control hazardous air pollutants.
- BART for SO_2 emissions was optimizing the existing control equipment for removal of SO2.

However, these limits never became finalized as, on September 30, 2013, U.S. EPA disapproved the proposed NO_X and SO_2 limits contained in the SIP submitted by Minnesota.[14] While U.S. EPA agreed with Minnesota's determination of which sources were subject to BART and that BART for PM emissions from these sources was satisfied by the requirements of 40 CFR Part 63, Subpart RRRRR; U.S. EPA developed a FIP to address the deficiencies in the Minnesota SIP.

On February 6, 2013, U.S. EPA promulgated a Taconite Regional Haze FIP that included BART limits for taconite furnaces subject to BART in Minnesota with an effective date of March 8, 2013.[15] Cliffs Natural Resources Inc., ArcelorMittal USA LLC, and the State of Michigan petitioned the 8th Circuit Court of Appeals for a review of the FIP and filed a joint motion to stay the FIP which was granted on June 14, 2013.[16] A settlement agreement between the mentioned parties and U.S. EPA was reached to resolve certain items in the 2013 FIP. The settlement agreement was published in the Federal Register on January 30, 2015, executed on April 9, 2015, and prompted U.S. EPA to reconsider the 2013 FIP.[17]

U.S. EPA proposed revisions to the 2013 Taconite Regional Haze FIP on October 22, 2015, which proposed to revise the BART emission limits and compliance schedules for the following taconite facilities: United Taconite, Hibbing Taconite, Tilden Mining, and ArcelorMittal Minorca Mine.[18] U.S. EPA proposed to revise the NO_X limits and compliance schedules for all four facilities and to revise the SO_2 requirements for Tilden Mining and United Taconite. On April 12, 2016, U.S. EPA finalized the revisions to the 2013 FIP and the final rule (2016 FIP) was effective on May 12, 2016.[19]

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).[20] 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

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[14] *See* Approval and Promulgation of Air Quality Implementation Plans; States of Michigan and Minnesota; Regional Haze, *78 Fed. Reg. 59825 (Sept. 30, 2013).*

[15] *See* Approval and Promulgation of Air Quality Implementation Plans; States of Minnesota and Michigan, *78 Fed. Reg. 8706 (Feb. 6, 2013).*

[16] *See* Revision to Taconite Federal Implementation Plan, *80 Fed. Reg. 64160 (Oct. 22, 2015).*

[17] *See* Proposed Settlement Agreement, *80 Fed. Reg. 5111 (Jan. 30, 2015).*

[18] *See* Revision to Taconite Federal Implementation Plan, *80 Fed. Reg. 64160 (Oct. 22, 2015).*

[19] *See* Revision to 2013 Taconite Federal Implementation Plan Establishing BART for Taconite Plants, *81 Fed. Reg. 21672 (Apr. 12, 2016).*

[20] *See* Order dated November 15, 2016 in response to U.S. EPA's Petition to reconsider the original 2013 Taconite FIP, EPA-R05-OAR-2017-0066-0009 (8th Cir. 2016).

issued. The deadlines contained in the 2016 FIP were never stayed and apply as promulgated (e.g., 6 months after May 12, 2016).

While U.S. EPA reached an agreement with Cliffs Natural Resources Inc., ArcelorMittal USA LLC, and the State of Michigan regarding the issues raised in petitions for the 2013 FIP, the petitions for review of disapproval of Minnesota's Regional Haze SIP remain pending. In response to U.S. EPA's September 30, 2013 disapproval of Minnesota's Regional Haze SIP, Cliffs Natural Resources Inc. petitioned U.S. EPA on November 26, 2013, to reconsider the partial disapproval of Minnesota's Regional Haze SIP.[21] Further, Cliffs Natural Resources Inc. also filed petitions for review and administrative reconsideration of the 2016 FIP.[22] These petitions for review remain pending and are being held in abeyance pending approval of a second settlement agreement.

U.S. Steel also 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).[23] U.S. EPA later denied those petitions for reconsideration on January 18, 2017, based on their determination that the petitions did not meet the two-step test to determine whether reconsiderations should be granted, as required by section 307(d)(7)(B) of the Clean Air Act.[24] On February 1, 2018, U.S. Steel submitted a petition for review of the denial action.[25] As a result, U.S. EPA and the taconite facilities are currently working to resolve the disagreements through settlement discussions.

If a settlement agreement is reached with the Minnesota taconite facilities named in the FIPs (Cleveland-Cliffs Minorca Mine, Hibbing Taconite Company, Northshore Mining Company, United Taconite - Fairlane Plant, U.S. Steel - Keetac, and U.S. Steel - Minntac), U.S. EPA must publish a Federal Register notice announcing the settlement agreement, initiate a public notice and comment period, and respond to any comments received. 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.[26] Most recently, U.S. EPA published a final rule revising the FIP as it pertains to U.S. Steel - Minntac on March 2, 2021.[27]

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[21] *See* Revision to Taconite Federal Implementation Plan, 80 Fed. Reg. 64160 (Oct. 22, 2015); Petition for Administrative Reconsideration of the Partial Disapproval of Air Quality Implementation Plans for Regional Haze for the States of Michigan and Minnesota, EPA-R05-OAR-2015-0196 (Nov. 26, 2013).

[22] *See* Revision to 2013 Taconite Federal Implementation Plan Establishing BART for Taconite Plants, 81 Fed. Reg. 21672 (Apr. 12, 2016).

[23] *See* Petition for Reconsideration and for Stay Pending Reconsideration (with Exhibits) of February 6, 2013 Regional Haze FIP, EPA-R05-OAR-2017-0066-0004 (Nov. 26, 2013); June 13, 2016 Petition for Administrative Reconsideration of April 12, 2016 Regional Haze FIP, EPA-R05-OAR-2017-0067-0005 (June 13, 2016).

[24] *See* Final Action on Petitions for Reconsideration, 82 Fed. Reg. 57125 (Dec. 4, 2017); January 18, 2017 Denial of U.S. Steel's Petition for Reconsideration of February 6, 2013 Regional Haze FIP and April 12, 2016 Revised FIP, EPA-R05-OAR-2017-0066-0008 (Jan. 18, 2017).

[25] *See* Petition for Judicial Review, U.S. Steel Corp. v. U.S. EPA, No. 18-1249 (8th Cir. Feb. 2, 2018).

[26] *See* Revision to Taconite Federal Implementation Plan, 85 Fed. Reg. 6125 (proposed Feb. 4, 2020) (to be codified at 40 CFR Part 52). *See also* Revision to Taconite Federal Implementation Plan; Notice of Public Hearing, 85 Fed. Reg. 60942 (Sept. 29, 2020).

[27] *See* Air Plan Approval; Minnesota; Revision to Taconite Federal Implementation Plan, 86 Fed. Reg. 12095 (Mar. 2, 2021).

1.4. U.S. EPA's Regional Haze Federal Implementation Plan (FIP) for visibility

The MPCA initially did not perform a BART determination for BART-subject electric generating units (EGUs) to evaluate NO_X and SO_2 because of Minnesota's inclusion in the Clean Air Interstate Rule (CAIR). U.S. EPA found that, as a whole, the CAIR cap-and-trade program improved visibility more than implementing BART in states affected by CAIR.[28] A state that chose to participate in the CAIR program did not need to require its BART-eligible EGUs to install, operate, and maintain BART. A state using CAIR as BART for its EGUs still needed a BART determination for PM emissions, as NO_X and SO_2 emissions were addressed by CAIR. However, subsequent legal uncertainty concerning CAIR, as well as several comments received on the draft SIP, led to reconsideration of the decision to allow CAIR to substitute for BART. Therefore, the MPCA made BART determinations for BART-subject EGUs.

Minnesota was removed from the CAIR program, following the remand of the CAIR program to U.S. EPA, and was later included in the Cross-State Air Pollution Rule (CSAPR), as described in 40 CFR § 52.1240 and 40 CFR § 52.1241. On December 30, 2011, U.S. EPA published in the Federal Register a proposal that CSAPR would result in greater visibility improvement in all Class I areas than implementation of source-specific BART at individual power plants.[29] As a result, the MPCA determined that CSAPR served as an alternative to BART for BART-subject EGUs and those sources simply needed to comply with their obligations under CSAPR in order to meet their BART obligations. However, the MPCA did include site-specific BART requirements for Xcel Energy - Sherburne Generating Plant to address the requirement in 40 CFR § 51.302(c) related to BART for Reasonably Attributable Visibility Impairment (RAVI).[30]

In MPCA's 2009 Regional Haze SIP and subsequent 2012 SIP supplement, the MPCA identified site specific NO_X, SO_2, and PM_{10} BART determinations for EGUs at utility power plants. For Xcel Energy - Sherburne Generating Plant, the MPCA identified BART for Units 1 and 2 as low NO_X burners and overfire air on Unit 1 and additional computerized combustion controls for both boilers for NO_X emissions, installation of sparger tubes and lime injection in the existing scrubber for SO_2 emissions, and usage of existing wet electrostatic precipitators as emission controls for PM emissions. It also included daily emission limits for NO_X, SO_2, and PM emissions applicable to the common stack for both boilers.

However, these limits never became finalized as BART requirements when U.S. EPA deferred action on the proposed NO_X and SO_2 limits contained in the SIP submitted by Minnesota. While U.S. EPA approved Minnesota's determination of which sources were subject to BART and participation in CSAPR as a BART alternative for SO_2 and NO_X emissions from EGUs, they did not approve the limits to represent BART on a source-specific basis. U.S. EPA stated that they intended to act in the future concerning the BART requirements that apply to Xcel Energy - Sherburne Generating Plant as it was certified as a source of RAVI.[31] Subsequently, U.S. EPA developed a FIP to address the RAVI obligations in the Minnesota SIP.

As a means of settling the claims against the U.S. EPA in National Parks Conservation Association v. EPA, Civ. No. 12-3043 (D. Minn.), the U.S. EPA entered into a settlement agreement with Xcel Energy on May 15, 2015. On March 7, 2016, U.S. EPA promulgated a FIP for visibility to establish the emission limits

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[28] *See* Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 Fed. Reg. 39104 (July 6, 2005)

[29] *See* Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans, 76 Fed. Reg. 82219 (Dec. 30, 2011); *see also* Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans, 77 Fed. Reg. 33642 (June 7, 2012).

[30] *See* Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Regional Haze, 77 Fed. Reg. 34801 (June 12, 2012).

[31] *See id.*

identified in the settlement agreement for Xcel Energy - Sherburne Generating Plant with an effective date of April 6, 2016.[32] These emission limits and associated compliance provisions are identified in the Minnesota RAVI FIP under 40 CFR § 52.1236.

1.5. Minnesota's Five-Year Progress Report (first implementation period)

The Regional Haze Rule also requires states provide interim progress reports outlining the status of required Regional Haze SIP elements, originally due five years after submittal of each state's initial Regional Haze SIP. The five-year progress report provides states the opportunity to assess, and if necessary, strengthen and/or correct their Regional Haze SIP. It also provides the "opportunity for public input on the state's (and the U.S. EPA's) assessment of whether the approved regional haze SIP is being implemented appropriately and whether reasonable visibility progress is being achieved consistent with the projected visibility improvement in the SIP."[33]

The report reviewed plan elements as specified in 40 CFR § 51.308(g) of the Regional Haze Rule, including:

- Status of control strategies in the Regional Haze SIP,
- Emissions reductions from Regional Haze SIP strategies,
- Visibility progress,
- Emissions progress,
- Assessment of changes impeding visibility progress,
- Assessment of current strategy,
- Review of visibility monitoring strategy, and
- Determination of Adequacy.

The submittal of Minnesota's Regional Haze SIP to U.S. EPA in 2009 set the deadline for submittal of the first implementation period five-year progress report as December 31, 2014. The progress report was required to be in the form of an implementation plan revision that complies with SIP procedural requirements outlined in 40 CFR §§ 51.102-103.

In the progress report, the MPCA stated that controls identified in Minnesota's Regional Haze SIP have either been implemented or were expected to be implemented by 2018. Although some of the Regional Haze SIP strategies had not yet produced quantifiable emissions reductions, at the time Minnesota had met the emissions reduction goal from the Northeast Minnesota Plan portion of the long-term strategy. Additionally, although CSAPR had not yet been implemented, Minnesota's power plants have reduced emissions to levels below those identified in CSAPR budgets.

When the progress report was submitted both of Minnesota's Class I areas had seen improvements in worst-day visibility conditions, and Minnesota had achieved the reasonable progress goal for Voyageurs and Boundary Waters. Minnesota achieved its statewide modeled 34% emissions reduction in total SO_2 emissions (2002-2018) by 2008 and saw a 63% reduction in SO_2 point-source emissions by 2012. Minnesota achieved a 38% emissions reduction in total NO_X emissions by 2011, nearly reaching its entire (2002-2018) modeled emissions reductions goal of 41% and saw a 52% reduction in NO_X point-source emissions by 2012.

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[32] *See* Air Plan Approval; Minnesota; Revision to Visibility Federal Implementation Plan, 81 Fed. Reg. 11668 (March 7, 2016).
[33] U.S. EPA, General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans (Intended to Assist States and EPA Regional Offices in Development and Review of the Progress Reports) 3 (Apr. 10, 2013), https://www.epa.gov/sites/default/files/2016-03/documents/haze_5year_4-10-13.pdf.

Minnesota did not anticipate any significant changes in either in-state or out-of-state emissions that would impede visibility progress. Based on the already-achieved emissions reductions and reasonable progress goals, and the anticipation of further emissions reductions, Minnesota believed its current Regional Haze SIP strategy was sufficient. Furthermore, Minnesota continued to rely upon participation in the Interagency Monitoring of Protected Visual Environments (IMPROVE) program to meet its monitoring strategy requirements with no modifications to the strategy determined necessary at the time.

The MPCA submitted its five-year progress report on December 30, 2014, and determined that Minnesota's Regional Haze SIP was adequate and required no further substantive revision at the time to achieve 2018 reasonable progress goals. The U.S. EPA approved Minnesota's progress report on June 28, 2018, with an effective date of July 30, 2018.[34]

1.6. Minnesota's Regional Haze SIP (second implementation period)

40 CFR § 51.308(f) requires that states must revise and submit their Regional Haze SIP revision to the U.S. EPA by July 31, 2021 (second implementation period), July 31, 2028 (third implementation period), and every 10 years thereafter (subsequent implementation periods). In each Regional Haze SIP revision, states must address regional haze in each mandatory Class I federal area located within the state and each mandatory Class I federal area located outside the state that may be affected by emissions from within the state. Additionally, the July 31, 2021, Regional Haze SIP revision must include a commitment by the state to meet the requirements of 40 CFR § 51.308(g).

In the first implementation period, the focus of the Regional Haze Rule was on establishing BART for certain older sources and reasonable progress towards national visibility goals. In the second implementation period there are no BART requirements; therefore, the focus is on making reasonable progress.

The U.S. EPA has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2). At minimum, the reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. The four factors are:

1. The costs of compliance.
2. The time necessary for compliance.
3. The energy and non-air quality environmental impacts of compliance.
4. The remaining useful life of the source.

In the second implementation period, the focus of the Regional Haze Rule is on making reasonable progress. The MPCA sent request for information (RFI) letters to 17 facilities requesting that they prepare and submit a four-factor analysis for the identified emission units that examined potential control measures to reduce emissions of NO_X and SO_2. The MPCA did not specify which control measures should be considered, instead referencing that the analyses should follow the recommendations identified in U.S. EPA's August 2019 Guidance.

In response, several facilities provided additional information regarding the remaining useful life and/or the effectiveness of existing control measures of specific emission units at their facilities. In general, the emission reduction measures that the MPCA is relying on for the second implementation period are the

[34] *See* Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Regional Haze Progress Report, 83 Fed. Reg. 30350 (June 28, 2018).

planned retirements of several large emission units and the continued implementation of effective control technologies that other sources already have in place.

Minnesota's long-term strategy includes a revision to the Northeast Minnesota Plan, created in the first implementation period, to establish new emission reduction targets for 2025 and 2028 to serve as a backstop for NO_X and SO_2 emissions in the Northeastern region of Minnesota. The original Northeast Minnesota Plan established non-binding targets for combined NO_X and SO_2 emissions at a 20% reduction by 2012 and a 30% reduction by 2018 (as compared to the 2002 baseline emissions inventory) from permitted sources in Northeastern Minnesota that emit over 100 tons per year of either NO_X or SO_2. The new emission reduction targets establish a 30% reduction by 2025 and a 40% reduction by 2028 from a baseline year of 2018 from permitted sources in Northeastern Minnesota that emit over 100 tons per year of either NO_X or SO_2.

Though the new emissions reduction goals are not enforceable upon the permitted sources, they provide an incentive for continued progress in the region. This also allows the MPCA to account for emissions from new or modified facilities to ensure that visibility conditions do not worsen and serves as a trigger of sorts that leads to considering and/or implementing additional, potentially more aggressive, emission reduction measures as part of the 2025 progress report or the 2028 comprehensive update.

The Regional Haze Rule requires states to address the progress report requirements within each Regional Haze SIP revision, so that the revision will also serve as a progress report. Minnesota's progress report for the first implementation period was previously submitted on December 30, 2014. In U.S. EPA's August 2019 Guidance, they recommend that the progress report elements included in the SIP revision for the second implementation period cover a time period approximately from the first full year that was not in the previous progress report through a year that is as close as possible to the submission date of the SIP revision.[35]

For Minnesota, this means that the relevant time period addressed for each of the elements of 40 CFR §51.308(g)(1)-(5) is roughly 2015 through 2021. The progress report requirements are addressed in Sections 2.8.3 and 2.10 and cover the requirements of 40 CFR §51.308(g)(1)-(5), including:

- Status of control strategies in the Regional Haze SIP,
- Emissions reductions from Regional Haze SIP strategies,
- Visibility progress,
- Emissions progress, and
- Assessment of changes impeding visibility progress.

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

2. Required Regional Haze SIP elements

This document provides information regarding the MPCA's comprehensive update to Minnesota's Regional Haze SIP at 40 CFR § 52.1220. This Regional Haze SIP addresses the requirements of the Regional Haze Rule for the second implementation period, which extends through 2028. The required content of this Regional Haze SIP is specified in 40 CFR § 51.308(f).

Minnesota has two Class I areas within its borders, the Boundary Waters Canoe Area Wilderness (Boundary Waters) and Voyageurs National Park (Voyageurs). To meet the core requirements for regional haze for these areas, Minnesota must submit a Regional Haze SIP that contains the plan elements and supporting documentation for all required analyses identified in 40 CFR § 51.308(f). These requirements were last revised in 2017.[36]

On August 20, 2019, the U.S. EPA issued guidance (August 2019 Guidance) to assist states as they develop plans to address visibility impairment for the second implementation period under the Regional Haze Rule.[37] This guidance provides recommendations for states to use as they develop their Regional Haze SIP submittals; including key process steps that U.S. EPA anticipates states will typically follow when developing a Regional Haze SIP for the second implementation period.

On July 8, 2021, U.S. EPA also issued a clarification memorandum (July 2021 Clarification Memo) in response to questions and information that they received regarding Regional Haze SIP development.[38] In this memo, U.S. EPA provides additional clarifications regarding the Regional Haze Rule and the August 2019 Guidance in the context of questions and information shared from states and U.S. EPA Regional Offices during Regional Haze SIP development.

Both the August 2019 Guidance and July 2021 Clarification Memo are referenced throughout Minnesota's Regional Haze SIP. This section of Minnesota's Regional Haze SIP is organized by the suggested SIP development steps identified in the August 2019 Guidance and outlined below:

- Step 1 - Ambient data analysis
- Step 2 - Determination of affected Class I areas in other states
- Step 3 - Selection of sources for analysis
- Step 4 - Characterization of factors for emission control measures
- Step 5 - Control measures necessary to make reasonable progress
- Step 6 - Regional scale modeling of the long-term strategy (LTS) to set reasonable progress goals (RPGs) for 2028
- Step 7 - Progress, degradation, and uniform rate of progress (URP) glidepath checks
- Step 8 - Additional requirements for SIPs

2.1. Step 1 - Ambient data analysis

The Regional Haze Rule requires states to track visibility improvements over time through quantifying historical and projected visibility conditions using specific metrics. States with Class I areas within their borders are required to identify the 20% most visibly impaired days caused by human activity; identify

[36] *See* Protection of Visibility: Amendments to Requirements for State Plans, 82 Fed. Reg. 3078 (Jan. 10, 2017).
[37] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra.*
[38] *See* U.S. EPA, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (July 8, 2021), *https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf* [hereinafter July 2021 EPA Clarifications*].*

the 20% clearest days; and determine the baseline, current, and natural visibility conditions for each Class I area within the state.

On December 20, 2018, the U.S. EPA issued guidance that addresses this topic in further detail.[39] The guidance updates U.S. EPA's recommended methods on tracking visibility metrics and on estimating international anthropogenic impacts and optional adjustment to the Uniform Rate of Progress (URP) glidepath.

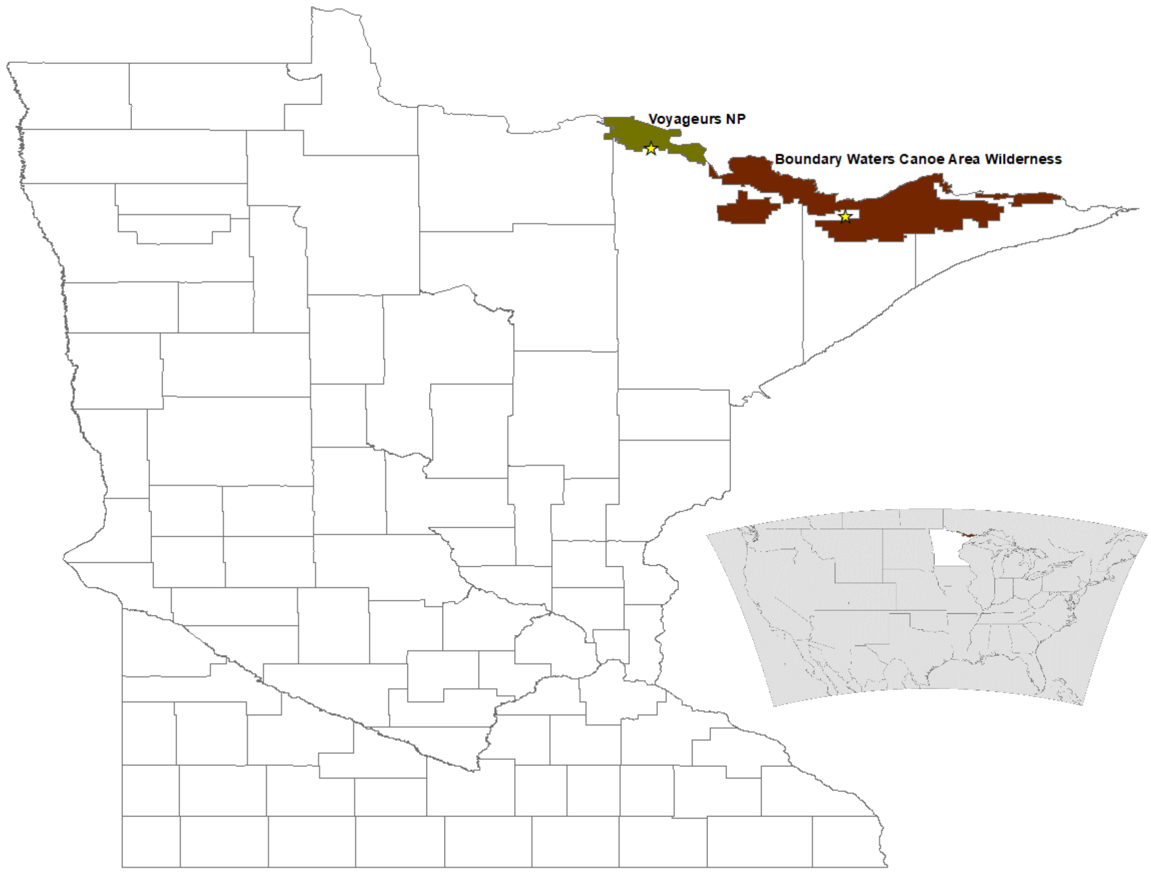
The required content of the ambient data analysis is specified in 40 CFR § 51.308(f)(1). These requirements identify the calculation of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress. For the Boundary Waters and Voyageurs, Minnesota must determine the following:

- Baseline visibility conditions for the most impaired and clearest days.
- Natural visibility conditions for the most impaired and clearest days.
- Current visibility conditions for the most impaired and clearest days.
- Progress to date for the most impaired and clearest days.
- Differences between current visibility condition and natural visibility condition.
- Uniform rate of progress.

There are two Class I areas protected by the Regional Haze Program located in Minnesota, Voyageurs and Boundary Waters. Both Class I areas are located in Northern Minnesota along the border with Canada, as shown in Figure 2. Yellow star shaped icons in the Figure identify the location of monitoring stations in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network for each Class I area.

[39] *See* U.S. EPA, Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program (Dec. 2018), *https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf* [hereinafter Dec. 2018 EPA Technical Guidance].

Figure 2. Minnesota Class I areas, Voyageurs and Boundary Waters



The core of the visibility assessment is the baseline and natural visibility conditions based on observed data collected at the IMPROVE monitors, made available through the Federal Land Manager Environmental Database (FED).[40] The baseline conditions are developed from five years of monitoring data and represent the starting point from which reasonable progress is measured. The Regional Haze Rule prescribes the baseline period as the years 2000-2004.[41] The rule defines baseline visibility conditions as the average of the 20% of days with the most impaired visibility and the average of the 20% of days with the least impaired visibility (or "clearest days"). The baseline conditions are calculated from the monitoring data for each year of the baseline, then averaged over the 5-year baseline period. This process is repeated each year, dropping one year of data from the beginning of the 5-year period and adding one year of new data to the end of the 5-year period. The final result of the visibility calculation is assigned to the last year of the 5-year period (e.g., 2000-2004 is assigned to 2004).

Fine particles less than 2.5 microns (µm) in size ($PM_{2.5}$) are primarily responsible for impaired visibility.[42] $PM_{2.5}$ is composed of several pollutant species; nitrate, sulfate, organic carbon, elemental carbon, fine

[40] *See* FEDERAL LAND MANAGER ENVIRONMENTAL DATABASE, http://views.cira.colostate.edu/fed/ (last visited June 13, 2021).
[41] *See* 40 CFR § 51.308(d)(2).
[42] *See* William C. Malm, Coop. Inst. For Rsch. In the Atmosphere, Nat'l Parks Serv. Visibility Program, Introduction to Visibility 24 (1999).

soil, sea salt, and water. Coarse particulate mass (>2.5 µm, but ≤10 µm diameter) is also included in the visibility metrics.

MPCA has calculated visibility metrics for Boundary Waters and Voyageurs using the individual measured components described above in the IMPROVE algorithm adopted by the IMPROVE Steering Committee in December 2005.[43] Details on the equation and its use for calculating visibility metrics at Boundary Waters and Voyageurs are provided in Appendix A. MPCA's Regional Haze SIP Technical Support Document.

The solution to the IMPROVE equation is in the form of light extinction (b_{ext}) in units of inverse megameters (Mm^{-1}). The Regional Haze Rule requires visibility to be converted to, and expressed in, deciviews (dv). In the deciview scale, "a 1 to 2 deciview difference corresponds to a small, visibly perceptible change in scene appearance…" by the human observer.[44]

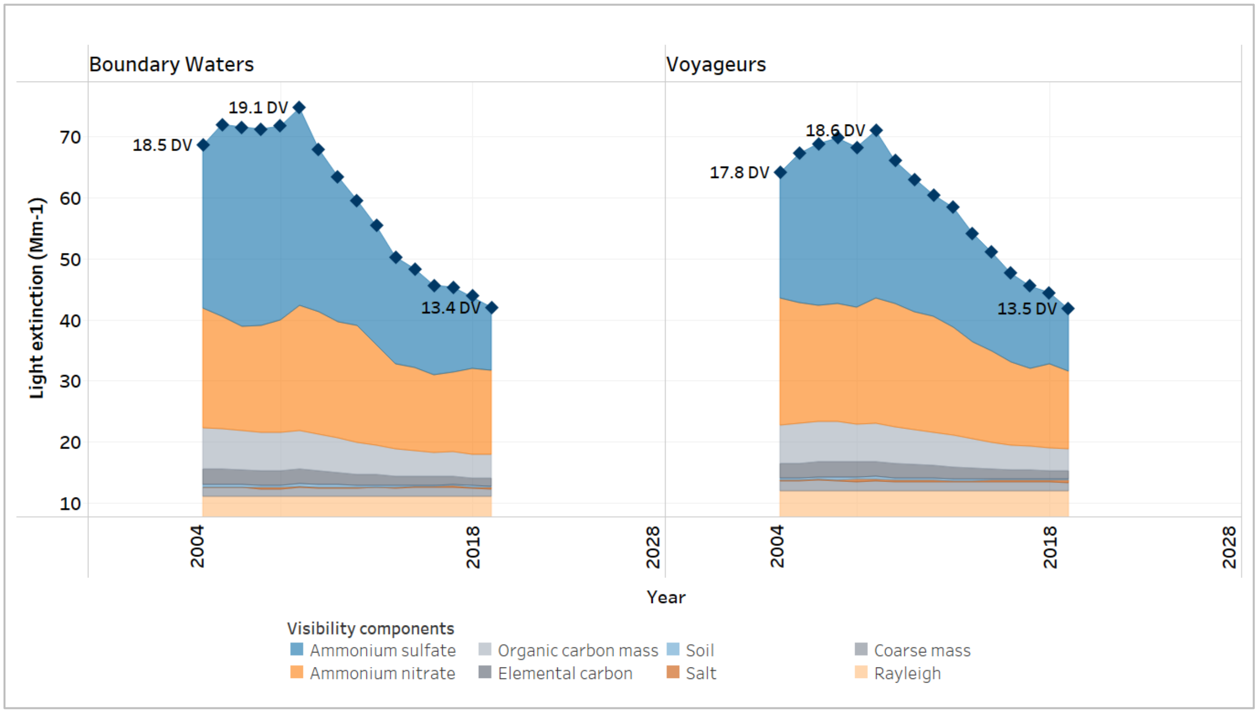
Data from the IMPROVE monitoring sites at Boundary Waters and Voyageurs indicate that ammonium sulfates (NH_4SO_4) and ammonium nitrates (NH_4NO_3) continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and ammonia (NH_3). Other pollutants that can impair visibility include fine and coarse particulate matter (PM) and volatile organic compounds (VOCs).

Figure 3 shows the monitored visibility impairment, as light extinction, from the identified visibility components through 2019 for the most impaired visibility conditions at Boundary Waters and Voyageurs. The 5-year rolling average value of total light extinction is converted to deciviews and superimposed at the top of each year.

[43] *See* Marc Pitchford et al., *Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data,* 57 J. of the Air and Waste Mgmt. Ass'n 1326, 1326-36 (2007).

[44] Marc Pitchford & William C. Malm, *Development and Application of a Standard Visual Index,* 28 Atmospheric Env't 1049, 1049-54 (1994).

Figure 3. Visibility components for most impaired visibility conditions at Boundary Waters and Voyageurs



Minnesota's Class I areas have shown marked improvements in visibility since the initial baseline period. The measured improvements in visibility impairment on the most impaired days can be attributed to reductions in ammonium sulfate, and to a lesser extent ammonium nitrate. These improvements are likely a result of enforceable controls/reductions for SO_2 and NO_X emissions at power plants, industrial facilities, and motor vehicles.

Data for specific years is presented in Table 1, further illustrating the relative dominance nitrates and sulfates have in causing visibility impairment at Boundary Waters and Voyageurs. For example, at Boundary Waters, sulfates and nitrates account for roughly 68% of the total visibility impairment in the initial baseline year (2004), 60% in the current baseline year (2016), and 59% in the initial projection year (2018).

Table 1. Visibility components at Boundary Waters and Voyageurs at initial baseline (2004), current baseline (2016), and initial projection year (2018)

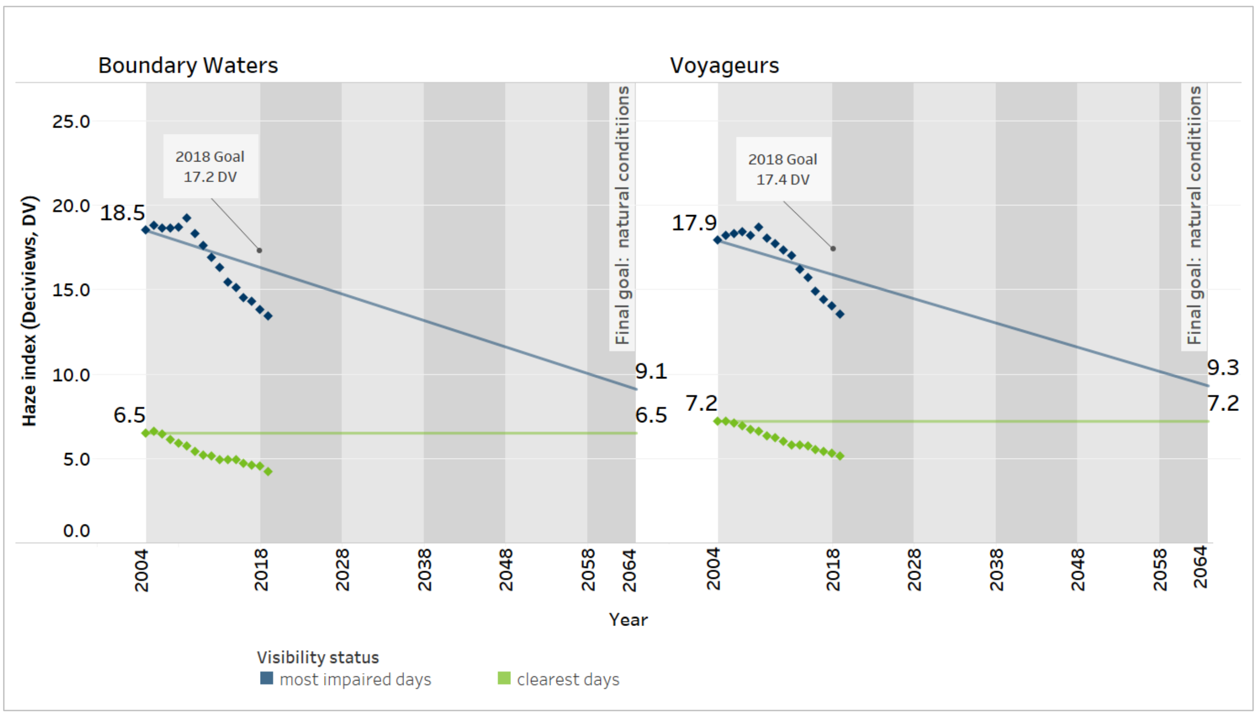
Class I area	Year	Total (dv)	Light extinction by component (B_{ext} expressed in Mm^{-1})[45]							
			Total	NH_4SO_4	NH_4NO_3	OCM	EC	Soil	Salt	Coarse Mass
Boundary Waters	2004	18.5	68.6	26.7	19.6	6.8	2.5	0.4	0.1	1.5
	2016	14.5	45.6	14.8	12.6	4.0	1.4	0.2	0.2	1.5
	2018	13.8	43.9	11.7	14.1	3.8	1.3	0.2	0.2	1.4

[45] *The value for the total column (B_{ext} as expressed in Mm^{-1}) includes the contribution of Rayleigh scattering; natural light scattering by gases in the atmosphere. The light extinction from Rayleigh scattering at Boundary Waters is 11 Mm^{-1} and at Voyageurs is 12 Mm^{-1}.*

Class I area	Year	Total (dv)	Light extinction by component (B_{ext} expressed in Mm^{-1})[45]							
			Total	NH_4SO_4	NH_4NO_3	OCM	EC	Soil	Salt	Coarse Mass
Voyageurs	2004	17.9	64.1	20.4	20.8	6.4	2.4	0.3	0.1	1.6
	2016	14.9	47.6	14.5	13.7	4.0	1.5	0.2	0.2	1.5
	2018	14.0	44.3	11.6	13.8	3.7	1.4	0.2	0.3	1.4

Figure 4 shows the visibility status at Boundary Waters and Voyageurs in the form required by rule for the ambient data analysis. The 2018 Reasonable Progress Goals from the first implementation period also appear on this Figure for reference. Section 2.7 describes the development of reasonable progress goals (RPGs) for the second implementation period and sets a new 2028 RPG displayed on an updated figure.

Figure 4. Visibility status at Boundary Waters and Voyageurs for the 20% most visibly impaired days and 20% clearest days



MPCA has created an interactive tool accessible from the Pollution Control Agency website (crtl + click on icon below) that allows the user to explore the visibility data for Boundary Waters and Voyageurs.[46] The tool provides the visibility metrics and species components that are updated each year, and regional influences on the 20 percent most impaired and clearest visibility days at Boundary Waters and Voyageurs.

[46] MPCA Data Services, VISIBILITY PROGRESS AT MINNESOTA CLASS I AREAS (May 6, 2021), https://public.tableau.com/app/profile/mpca.data.services/viz/RegionalHaze_visibility_metrics_public/Visibilityprogress (last visited June 24, 2022).

Explore visibility data for Minnesota Class I areas

This interactive tool shows the progress made toward interim goals for visibility, components of impaired visibility, and regional influences on the air in Minnesota Class I areas.

A breakdown of each rule requirement for each component of the tracking metrics for Boundary Waters and Voyageurs is provided below, along with tables containing calculated values for each element depicted in Figure 4. Details of the calculations and approach are provided in Appendix A. MPCA's Regional Haze SIP Technical Support Document.

2.1.1. Baseline visibility conditions for the most impaired and clearest days

40 CFR § 51.308(f)(1)(i) specifies the requirements for calculating baseline visibility conditions:

> *The period for establishing baseline visibility conditions is 2000 to 2004. The State must calculate the baseline visibility conditions for the most impaired days and the clearest days using available monitoring data. To determine the baseline visibility condition, the State must calculate the average of the annual deciview index values for the most impaired days and for the clearest days for the calendar years from 2000 to 2004. The baseline visibility condition for the most impaired days or the clearest days is the average of the respective annual values. For purposes of calculating the uniform rate of progress, the baseline visibility condition for the most impaired days must be associated with the last day of 2004. For mandatory Class I Federal areas without onsite monitoring data for 2000-2004, the State must establish baseline values using the most representative available monitoring data for 2000-2004, in consultation with the Administrator or his or her designee. For mandatory Class I Federal areas with incomplete monitoring data for 2000-2004, the State must establish baseline values using the 5 complete years of monitoring data closest in time to 2000-2004.*

Both Boundary Waters and Voyageurs each have a complete set of data for 2000-2004. Boundary Waters has a substitute dataset for this period because an equipment malfunction in 2002, 2003, and 2004 caused the loss of some $PM_{2.5}$ particle mass, elemental organic carbon mass and PM_{10} particle mass. The data loss invalidated three out of every seven samples for these components. In order to use the valid data, e.g., the nitrates and sulfates, missing elements were substituted with data from Voyageurs. The data substitution is further described in Appendix A. MPCA's Regional Haze SIP Technical Support Document.

Table 2. Baseline visibility conditions at Boundary Waters and Voyageurs

Minnesota Class I area	Year	Most impaired (dv)		Clearest (dv)	
		Annual	Five-year Average	Annual	Five-year Average
Boundary Waters	2000	18.6		6.0	
	2001	19.4		6.9	
	2002	18.8		7.1	
	2003	18.5		6.8	
	2004	17.1	18.5	5.8	6.5

Minnesota Class I area	Year	Most impaired (dv)		Clearest (dv)	
		Annual	Five-year Average	Annual	Five-year Average
Voyageurs	2000	18.0		7.1	
	2001	17.7		7.1	
	2002	17.8		7.5	
	2003	18.8		7.7	
	2004	17.2	17.9	6.4	7.2

2.1.2. Natural visibility conditions for the most impaired and clearest days

40 CFR § 51.308(f)(1)(ii) specifies the requirements for calculating natural visibility conditions:

A State must calculate natural visibility condition by estimating the average deciview index existing under natural conditions for the most impaired days or the clearest days based on available monitoring information and appropriate data analysis techniques.

MPCA calculated natural conditions with the method described in Appendix A. MPCA's Regional Haze SIP Technical Support Document. MPCA also refers to the natural conditions in this context as the 2064 endpoint.

Table 3. 2064 end points at Boundary Waters and Voyageurs

Visibility Conditions	Boundary Waters		Voyageurs	
	Most impaired	Clearest	Most impaired	Clearest
End point (2064) (dv)	9.1	6.5	9.3	7.2

2.1.3. Current visibility conditions for the most impaired and clearest days

40 CFR § 51.308(f)(1)(iii) specifies the requirements for calculating current visibility conditions:

The period for calculating current visibility conditions is the most recent 5-year period for which data are available. The State must calculate the current visibility conditions for the most impaired days and the clearest days using available monitoring data. To calculate each current visibility condition, the State must calculate the average of the annual deciview index values for the years in the most recent 5-year period. The current visibility condition for the most impaired or the clearest days is the average of the respective annual values.

Current conditions, based on the most recent monitoring data, for most impaired visibility far surpass the 2018 interim progress goals, as depicted in Figure 4, set in Minnesota's first round State Implementation Plan submitted to U.S. EPA in 2009. Current conditions for clearest visibility become more clear and do not degrade from baseline.

Table 4. Current visibility conditions at Boundary Waters and Voyageurs

Minnesota Class I area	Year	Most impaired (dv)		Clearest (dv)	
		Annual	Five-year average	Annual	Five-year average
Boundary Waters	2015	13.8	15.1	4.5	4.9
	2016	12.0	14.5	4.2	4.7
	2017	14.5	14.3	5.0	4.6
	2018	13.7	13.8	4.0	4.5
	2019	13.1	13.4	3.5	4.2

Minnesota Class I area	Year	Most impaired (dv)		Clearest (dv)	
		Annual	Five-year average	Annual	Five-year average
Voyageurs	2015	13.5	15.7	5.4	5.7
	2016	12.6	14.9	4.9	5.5
	2017	14.1	14.4	5.8	5.4
	2018	14.2	14.0	4.9	5.3
	2019	13.2	13.5	4.3	5.1

2.1.4. Progress to date for the most impaired and clearest days

40 CFR § 51.308(f)(1)(iv) specifies the requirements for calculating progress to date:

> *Actual progress made towards the natural visibility condition since the baseline period, and actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions, for the most impaired and for the clearest days.*

As described above, Minnesota Class I areas show marked progress toward clear air from baseline (2000 - 2004) to present.

Table 5. Visibility progress to date at Boundary Waters and Voyageurs

Year	Boundary Waters		Voyageurs	
	Most impaired 5-year average (dv)	Clearest days 5-year average (dv)	Most impaired 5-year average (dv)	Clearest days 5-year average (dv)
2004	18.5	6.5	17.9	7.2
2005	18.8	6.6	18.2	7.2
2006	18.6	6.4	18.3	7.1
2007	18.6	6.1	18.4	6.9
2008	18.7	5.9	18.2	6.7
2009	19.2	5.7	18.7	6.6
2010	18.3	5.4	18.0	6.3
2011	17.6	5.2	17.7	6.2
2012	16.9	5.1	17.3	6.0
2013	16.3	4.9	17.0	5.8
2014	15.4	4.9	16.2	5.8
2015	15.1	4.9	15.7	5.7
2016	14.5	4.7	14.9	5.5
2017	14.3	4.6	14.4	5.4
2018	13.8	4.5	14.0	5.3
2019	13.4	4.2	13.5	5.1

2.1.5. Differences between current visibility condition and natural visibility condition

40 CFR § 51.308(f)(1)(v) specifies the requirements for calculating the difference between current and natural visibility conditions:

> *The number of deciviews by which the current visibility condition exceeds the natural visibility condition, for the most impaired and for the clearest days.*

Current visibility conditions for the most impaired days at both Boundary Waters and Voyageurs are just above 4 dv over the 2064 endpoint. Visibility conditions for the clearest days are more than 2 dv clearer than the 2064 endpoint.

Table 6. Current vs. natural visibility conditions at Boundary Waters and Voyageurs

Visibility conditions	Boundary Waters		Voyageurs	
	Most impaired	Clearest	Most impaired	Clearest
Current (2019) (dv)	13.4	4.2	13.5	5.1
End point (2064) (dv)	9.1	6.5	9.3	7.2
Difference (2019 - 2064) (dv)	4.3	-2.3	4.2	-2.1

2.1.6. Uniform rate of progress

40 CFR § 51.308(f)(1)(vi)(A) specifies the requirements for calculating the URP:

> *The uniform rate of progress for each mandatory Class I Federal area in the State. To calculate the uniform rate of progress, the State must compare the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days in the mandatory Class I Federal area and determine the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064.*

Current conditions for most impaired visibility at both Boundary Waters (13.4 dv) and Voyageurs (13.5 dv) are below the URP reference line through 2028 (the second implementation period).

Table 7. Uniform rate of progress to reach natural visibility conditions

Minnesota Class I area	Uniform rate of progress by implementation period (dv)						
	2004	2018	2028	2038	2048	2058	2064
Boundary Waters	18.5	16.3	14.7	13.2	11.6	10.0	9.1
Voyageurs	17.9	15.9	14.5	13.0	11.6	10.2	9.3

2064 Endpoint adjustments. Additionally, 40 CFR § 51.308(f)(1)(vi)(B) specifies the requirements for proposing an adjustment to the uniform rate of progress to account for impacts from anthropogenic sources outside the United States and/or wildland prescribed fires conducted with a certain described objective described in the rule.

> *As part of its implementation plan submission, the State may propose (1) an adjustment to the uniform rate of progress for a mandatory Class I Federal area to account for impacts from anthropogenic sources outside the United States and/or (2) an adjustment to the uniform rate of progress for the mandatory Class I Federal area to account for impacts from wildland prescribed fires that were conducted with the objective to establish, restore, and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species during which appropriate basic smoke management practices were applied. To calculate the proposed adjustment(s), the State must add the estimated impact(s) to the natural visibility condition and compare the baseline visibility condition for the most impaired days to the resulting sum. If the Administrator determines that the State has estimated the impact(s) from anthropogenic sources outside the United States and/or wildland prescribed fires using scientifically valid data and methods, the Administrator may approve the proposed adjustment(s) to the uniform rate of progress.*

MPCA does not believe it has scientifically valid data and methods—this second implementation period—to estimate the impacts from human activity outside the United States and/or wildland prescribed fires to seek U.S. EPA approval to adjust the 2064 endpoint and the URP. Current measurements are well below the URP glidepath and have been steadily trending downward.

While Minnesota does not seek U.S. EPA approval to make adjustments to the 2064 end point this implementation period, readily available information by other organizations suggests Boundary Waters and Voyageurs could reach adjusted goals before year 2064. Table 8 contains adjusted 2064 endpoints for the second implementation period estimated through global or hemispheric photochemical modeling by U.S.EPA and the Electric Power Research Institute (EPRI) under contract with Ramboll.

Neither the U.S.EPA nor EPRI used the same version of the 2016 model platform as MPCA, which used 2016 v1b, and likely used a different source of 20% most impaired days for the contribution analysis. U.S.EPA describes its work as their "first comprehensive estimate of international anthropogenic emissions contributions to visibility impairment at Class I areas" and warrants additional scrutiny. While prescribed fire adjustments to the endpoint are also allowed under rule, neither U.S.EPA nor EPRI included them. Specified reasons for excluding prescribed fire adjustments are, natural conditions may already include some prescribed fire, there uncertainties in the emission estimates, prescribed fire activity varies significantly year to year, and the contribution from prescribed fire would be quite small compared to international impacts.

Table 8. Adjusted 2064 endpoints by other organizations for the most impaired visibility days at Boundary Waters and Voyageurs

Minnesota Class I area	Adjusted 2064 endpoints estimates (dv)		
	Natural conditions	U.S. EPA (September 2019)[47]	EPRI (September 2020)[48]
Boundary Waters	9.1	12.1	11.6
Voyageurs	9.3	12.5	12.0

The U.S.EPA adjusted endpoint suggests visibility impact at Boundary Waters would need to decrease from year 2019 an additional 1.3 dv (13.4 -12.1 dv), and Voyageurs an additional 1.0 dv (13.5 - 12.5 dv) dv, to reach the endpoint goal. The EPRI adjusted endpoint suggests visibility impact at Boundary Waters would need to decrease from year 2019 an additional 1.8 dv (13.4 - 11.6 dv), and Voyageurs an additional 1.5 dv (13.5 - 12.0 dv), to reach the endpoint goal. Between 2004 and 2009 there were measured increases in visibility impact at both Class I areas, but since 2009 the most impaired annual 5-year visibility impacts have declined per year an average 0.6 dv at Boundary Waters and an average 0.5 dv at Voyageurs. Should this trend continue, Boundary Waters and Voyageurs potentially could reach an adjusted endpoint by the third implementation period.

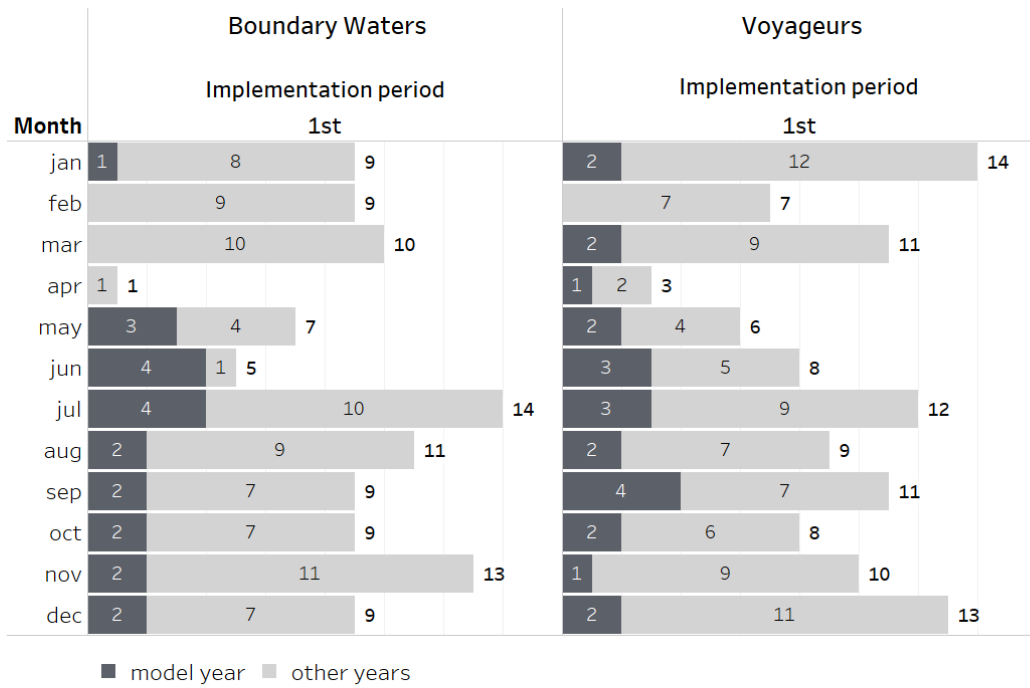
The December 2018 U.S. EPA guidance altered the tracking metric calculations between the first and second implementation period to account for natural wildfire impact on the selection of the 20 percent most impaired and 20 percent clearest visibility days.[49] The final Regional Haze Rule promulgated in 1999 did not distinguish between natural and human-caused contributions to visibility impairment when selecting the "most impaired days" and "clearest days" from the IMPROVE network monitoring data.[50]

[47] *See* U.S. EPA, Technical Support Document for EPA's Updated 2028 Regional Haze Modeling (Sept. 2019), https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling.
[48] *See* EPRI, Regional Haze Modeling to Evaluate Progress in Improving Visibility (Sept. 2020), https://www.epri.com/research/programs/113141/results/3002016531.
[49] *See* Dec. 2018 EPA Technical Guidance, *supra*.
[50] Regional Haze Regulations, 64 Fed. Reg. 35765 (July 1, 1999) (to be codified at 40 CFR Part 51).

U.S. EPA guidance at the time for calculating visibility tracking metrics included days affected by natural wildfire. While wildfire had some impact on the visibility tracking metrics for Boundary Waters and Voyageurs, it had remarkable impact on Class I areas in the Western United States, prompting the change in guidance.

Effects of tracking metric changes between the first and second implementation period on Boundary Waters and Voyageurs. In the first implementation period, observed values at Boundary Waters and Voyageurs during the baseline period, 2000 - 2004, indicate that the 20 percent worst visibility days are spread across all months of the year. During the warmer months several days were likely influenced by wildfires, which can contribute large amounts of organic carbon that significantly affect extinction. The monthly distribution of the number of worst visibility days calculated with the old metric procedures are shown in Figure 5.

Figure 5. Count of worst visibility days by month calculated with old tracking metric procedures[51]



The new tracking metric calculation procedures generally split organic carbon species into compartments; one compartment associated with natural wildfire and the other caused by human activities. The compartment containing human-caused organic carbon was retained in the sorting of days to identify the most impaired. The new metrics show many fewer most impaired days in the warmer months for both the first and second implementation periods. The monthly distribution of the number of worst visibility days calculated with the new metric procedures are shown in Figure 6.

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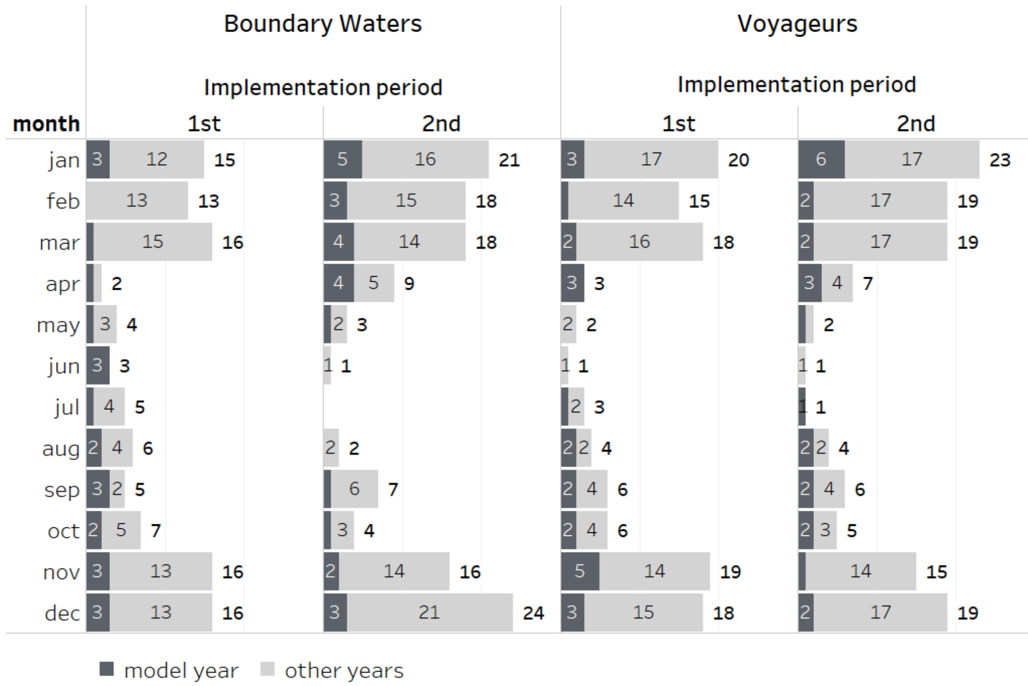
[51] *For the first implementation period, the model year is 2002 and the other four years in the tracking metric are 2000, 2001, 2003 and 2004*

Figure 6. Count of most impaired visibility days by month calculated with new tracking metric procedures[52]



The new metrics designed to limit wildfire impacts in tracking visibility impairment may also have other implications for Boundary Waters and Voyageurs. Modeling in the first implementation period was weighted toward days in the summer months when winds were predominantly from the South and Southeast. Modeling in the second implementation period is weighted more toward days in the fall and winter months when winds are predominantly from the Northwest and West.

2.2. Step 2 - Determination of affected Class I areas in other states

The Regional Haze Rule requires states to determine which Class I area(s) may be affected by emissions from within the state. States that host Class I areas within their borders are required to develop a long-term strategy that addresses visibility impairment for those Class I areas. All states, including those without Class I areas, are required to develop a long-term strategy to address visibility impairment for Class I areas in other states "that may be affected by emissions from the state."[53]

This means that Minnesota must develop a long-term strategy that addresses visibility impairment for:

- The Boundary Waters and Voyageurs located within Minnesota.
- Other Class I areas affected by emissions from within Minnesota.

The requirement to determine which Class I areas in other states may be affected by a state's own emissions is a part of the requirement to develop a long-term strategy specified in 40 CFR § 51.308(f)(2).

[52] *For the first implementation period, the model year is 2002 and the other four years in the tracking metric are 2000, 2001, 2003 and 2004. For the second implementation period, the model year is 2016 and the other four years in the tracking metric are 2014, 2015, 2017 and 2018*

[53] 40 CFR § 51.308(f)(2).

Long-term strategy for regional haze. *Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State.*

U.S. EPA provides additional information regarding how a state determines which Class I area in other states may be affected by emissions from within the state in its August 2019 Guidance. The guidance describes that each state is responsible for making its determination of what Class I areas may be affected by its emissions, a state has the flexibility to use any reasonable method for quantifying the impact of its own emissions on out-of-state Class I areas, and a state may use any reasonable assessment for this determination.[54]

U.S. EPA also provides two examples of how a state might make this determination:

- A state may retain determinations of affected Class I areas previously made in the first regional haze implementation period but should consider if assumptions from the first period have changed since those original assessments.
- A state may reassess determinations of affected Class I areas using a reasonable approach to assess which out-of-state Class I areas may be affected by aggregate emissions from within the state. This determination may be based on recent emissions or anticipated emissions in 2028 and must include all anthropogenic emission sources or be based on total statewide emissions.[55]

U.S. EPA identifies the most common approach in the first regional haze implementation period was to use a photochemical transport model to track the contribution due to emissions from whole states to specific Class I areas. U.S. EPA offers that this approach may also be used in the second regional haze implementation period, or a state may use another reasonable method such as a back trajectory-based approach.[56]

First implementation period. In the first implementation period, MPCA used a photochemical transport model to track the contribution of whole states or regions to Boundary Waters and Voyageurs. The November 2009 technical support document identified Minnesota as the largest contributor to visibility impacts at Boundary Waters and Voyageurs, as shown in Table 9, followed by sources located outside the boundary of the modeling domain, North Dakota, Wisconsin, Iowa, Missouri, Illinois, and Canada, respectively.[57]

The modeling domain in the first implementation period was relatively small, effectively cutting off the western portion of the contiguous United States. Boundary conditions enter and depart the modeling domain through the top, north, south, east, and west of the domain, making it difficult to pinpoint the source of visibility impacts entering from the boundary.

The model year was 2002 with projections to 2018 in the first implementation period. Monitoring data in the base year showed the majority of “worst” visibility days at Boundary Waters was due to sulfate. Although sulfate is formed all year round, most is formed in the warmer months of the year. Prevailing winds during warmer months are generally from the Southeast, which supported the conclusion Boundary Waters benefited from emissions reductions occurring in states to the East and Southeast. Monitoring data showed the majority of “worst” visibility days at Voyageurs were equally split between

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[54] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 8-9.
[55] *See id.*
[56] *See id.*
[57] *See* Minnesota Pollution Control Agency, Technical Support Document for the Minnesota State Implementation Plan for Regional Haze 85-89 (Nov. 9, 2009), https://www.pca.state.mn.us/sites/default/files/aq-sip2-13.pdf.

sulfate and nitrate. Ammonium nitrate forms in the cooler months (nitric acid in warmer months) when prevailing winds are from the West and Northwest, which supported the conclusion that Voyageurs would not benefit as much as Boundary Waters from emissions reductions occurring in states to the East and Southeast. Ammonium nitrate and sulfate need time to form in the atmosphere and are understood to travel large distances.

Table 9. State contributions in first implementation period to ammonium nitrate and sulfate at Boundary Waters and Voyageurs in 2018

Region name	Boundary Waters	Voyageurs
	Region contribution to visibility (%)	Region contribution to visibility (%)
Minnesota[58]	28	31
Boundary of model domain	11	15
North Dakota	6	13
Wisconsin	10	6
Iowa	8	7
Missouri	6	4
Illinois	6	3
Canada	3	5
All others	22	16

The MPCA focused the contribution analysis on Boundary Waters and Voyageurs in the first implementation period, concluding any future emissions reductions in Minnesota made to improve visibility in Boundary Waters and Voyageurs should have a commensurate effect on any other Class I areas impacted by Minnesota.

Second implementation period. While the determination of affected Class I areas in the first implementation period are informative, important assumptions changed between the first and second implementation period. The form of the tracking metrics changed to dampen the effects of fire on the chosen 20% most impaired visibility days. As described in Section 2.1.6, the new metrics show many fewer most impaired days in the warmer months for both the first and second implementation periods.

In the second implementation period, the timing for development of the 2016 modeling platform was not conducive to guide the direction of the long-term strategy through air quality modeling. Instead, MPCA used a surrogate analysis of emissions divided by distance (Q/d) to screen potential contributors to visibility impairment. Section 2.3.2 describes the Q/d approach in more detail. The Q/d process was completed late 2019 in time to send out requests for four-factor analyses January 2020. The contribution modeling began January 2021. Rather than direct the path of the long-term strategy, MPCA has used a photochemical transport model to serve as weight-of-evidence in general support of the long-term strategy and to foster interstate consultation.

Based on knowledge gained from the first implementation period, along with that learned from visibility trends with the revised tracking metrics (see Section 2.1), MPCA became fairly confident that:

- Minnesota would continue to be the largest contributor to visibility impairment at Boundary Waters and Voyageurs

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[58] *Six counties in Northeast Minnesota contributed more than half of the State impact to Boundary Waters and just under half of the impact to Voyageurs.*

- NO_X controls would be needed, with observed data trends increasingly showing ammonium nitrate dominating most impaired visibility days
- Boundary Waters and Voyageurs may not benefit as much from control measures in states located to the East and Southeast due to prevailing winds from the West and Northwest during periods of high ammonium nitrate production

Section 2.6. Regional Scale Modeling describes the development of the 2016 modeling platform. Section 2.2.1 below describes the use of the air quality model for contribution assessment.

2.2.1. Class I areas assessed for contribution to visibility impairment

Minnesota hosts the two Class I areas (Boundary Waters and Voyageurs). In addition to these two Class I areas, Minnesota assessed visibility contributions to some Class I areas in other states.

Michigan has two Class I areas located in the Upper Peninsula of Michigan; Isle Royale National Park, an island in Lake Superior, and Seney National Wildlife Refuge located in the eastern portion of the Upper Peninsula. For accessibility and maintenance reasons the IMPROVE monitor for Isle Royale is not located at the Class I area, but on the coast in the Upper Peninsula.

The remaining Class I areas assessed were chosen to capture those closest to the Minnesota border in each applicable direction of the compass. The Class I areas are Lostwood Wilderness and Theodore Roosevelt National Park in North Dakota, Badlands Wilderness in South Dakota, Hercules-Glades Wilderness Area and Mingo Wilderness Area in Missouri, and Mammoth Cave National Park in Kentucky. Table 10 below contains descriptions of each Class I area assessed. Figure 7 shows the boundaries of the Class I areas with yellow stars depicting the location of the IMPROVE monitor representing each Class I area assessed.

Figure 7. Class I areas assessed for contribution to visibility impairment

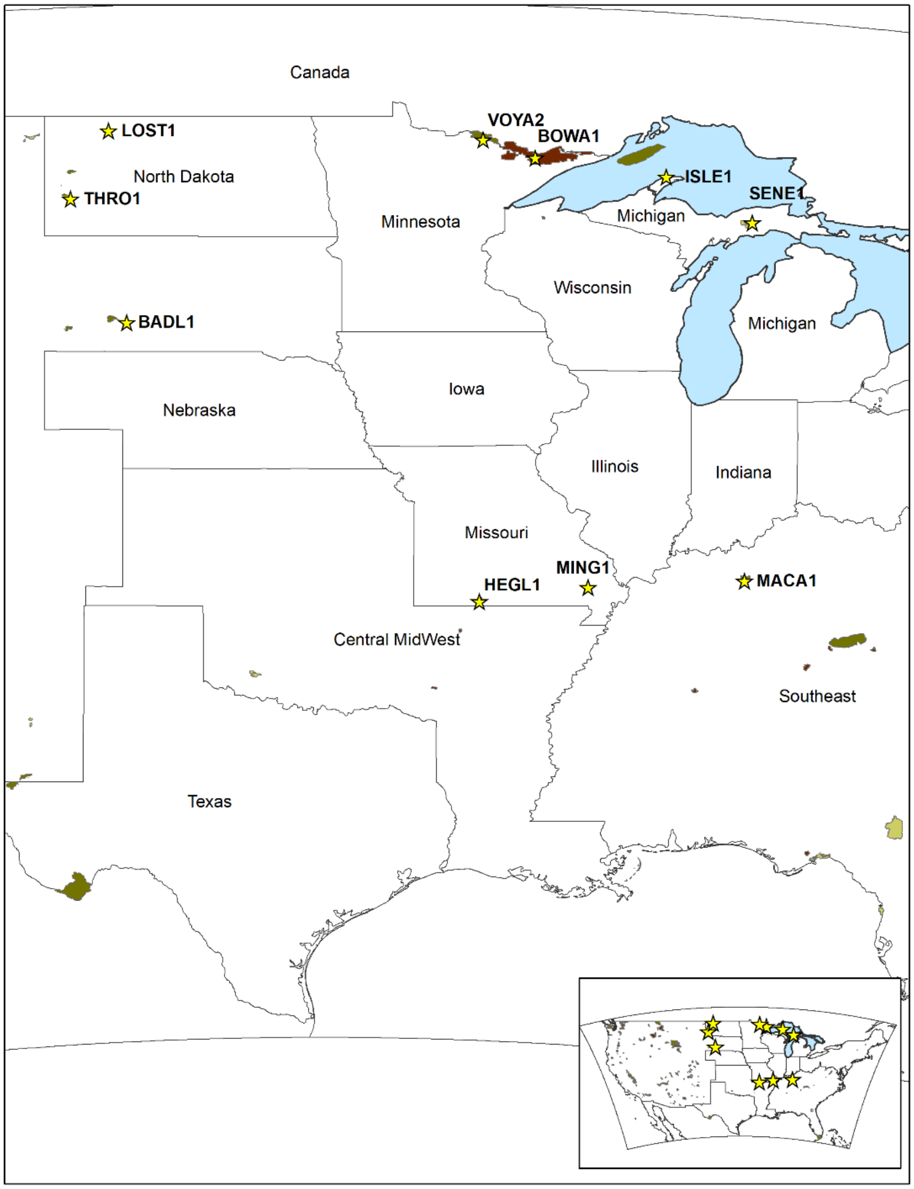


Table 10. Class I areas assessed for contribution to visibility impairment

Class I area	Acres	Affiliation	State located	Direction from Minnesota
Boundary Waters Canoe Area Wilderness	747,840	U.S. DA - Forest Service	Minnesota	-
Voyageurs National Park	114,964	U.S. DI - National Park Service	Minnesota	-
Isle Royale National Park	542,428	U.S. DI - National Park Service	Michigan	East
Seney Wilderness Area	25,150	U.S. DI - Fish & Wildlife Service	Michigan	East

Class I area	Acres	Affiliation	State located	Direction from Minnesota
Lostwood Wilderness	5,557	U.S. DI - Fish & Wildlife Service	North Dakota	West
Badlands Wilderness	64,250	U.S. DI - National Park Service	South Dakota	West
Theodore Roosevelt National Park	69,675	U.S. DI - National Park Service	North Dakota	West
Mingo Wilderness Area	8,000	U.S. DI - Fish & Wildlife Service	Missouri	South-Southeast
Hercules-Glades Wilderness Area	12,315	U.S. DA - Forest Service	Missouri	South
Mammoth Cave National Park	51,303	U.S. DI - National Park Service	Kentucky	Southeast

Contribution assessment approach. MPCA conducted the contribution assessment with version 7.10 of the Comprehensive Air quality Model with eXtensions (CAMx) photochemical model (described in Section 2.6), applying the Particulate Source Apportionment Technology (PSAT) module to track the original source of particulate species by geographic region and source category. MPCA intended to use the same version of the CAMx model (version 7.00) as that used to establish the RPG, but a bug in the source apportionment module of that version pushed the state to use the newer version just publicly released at the start of the study. All other aspects of the modeling approach are the same.

Available high performance computational resources, time, and the goal of the study, dictate the configuration of the PSAT simulation. MPCA's configuration includes:

- The entire 12US2 12 km domain as described in Section 2.6. Regional Scale Modeling.
- Sulfur and nitrogen tracer families resulting in output of particulate sulfate (from primary emissions plus secondarily formed), particulate nitrate (from primary emissions plus secondarily formed), and particulate ammonium.
- 16 geographic regions: Minnesota, North Dakota, Nebraska, Iowa, Wisconsin, Michigan, Missouri, Illinois, Indiana, Texas, Central Midwest, Northeast, Southeast, West, Canada/Mexico, and Water bodies. The geographic regions are shown in Figure 8.
- Central Midwest region comprised of Arkansas, Kansas, Louisiana, and Oklahoma.
- West region comprised of Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, South Dakota, Utah, Washington, and Wyoming.
- Southeast region comprised of Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.
- Northeast region comprised of Connecticut, Delaware, District of Columbia, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Vermont.
- 11 sector groups: Agriculture, Area, Dust, Electric Generating Units, Industry, Off-road, On-road, Oil/Gas, Residential Wood Combustion (RWC), Natural and Fire. Descriptions of the sector groups are in Section 2.6. Regional Scale Modeling.

Figure 8. Geographic regions for contribution analysis with PSAT

MPCA only included sulfur and nitrogen tracer families in the contribution analysis because monitored and modeled extinction for the 20 percent most impaired visibility days at Boundary Waters and Voyageurs are predominantly associated with sulfate and nitrate. MPCA determined nitrate and sulfate contribution using an approach similar to that taken by U.S. EPA in its updated 2028 regional haze modeling conducted to inform state implementation plan development in the second implementation period.[59] The process mimics that used to develop Relative Response Factors (RRFs) and Reasonable Progress Goals (RPGs) described in Section 2.6.

- Calculate an RRF from the air quality model output files. Assign the "bulk" overall average concentration output for 2028 to "modeled base year" and the 2028 PSAT concentration output for each geographic region to "modeled future."
- Assign the 2028 future visibility conditions used in the development of the RPG to "baseline monitoring conditions."
- Apply each sector group RRF to the newly defined "baseline monitoring conditions" for each species to estimate the contribution of each sector group. The extinction value of each sector group divided by the total extinction multiplied by 100 provides the percent contribution of each geographic region (and sector group).

The newly assigned baseline monitoring conditions for Boundary Waters and Voyageurs are the same as those used in the RPG calculations. The baseline monitoring conditions for Class I areas in other states were calculated using measurement data obtained from the Cooperative Institute for Research in the Atmosphere (CIRA). A more detailed description of how the MPCA calculated an RRF for particulate sulfate and particulate nitrate concentration for each geographic region and sector in the PSAT and how those were applied to projected 2028 monitored visibility conditions is available in Appendix A. MPCA's Regional Haze SIP Technical Support Document.

Overall contributions to visibility impairment. The revised tracking metrics in the second implementation period are designed to dampen the effects of fire and dust storms in the selection of

[59] *See* U.S. EPA, Technical Support Document for EPA's Updated 2028 Regional Haze Modeling (Sept. 2019), https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling.

the 20% most impaired (and clearest) days through adjustments to measured carbon and dust species. Dampening the effects of fire focuses attention on sulfate and nitrate and on anthropogenic sources. In the contribution analysis, fire accounts for nearly 3% and for 1% of light extinction due to sulfate and nitrate at Boundary Waters and Voyageurs, respectively. Natural sources account for about 6% of light extinction at both Class I Areas. Boundary conditions account for 38% and 40% of light extinction at Boundary Waters and Voyageurs, respectively. Anthropogenic sources account for nearly 54% and for 53% of light extinction due to sulfate and nitrate at Boundary Waters and Voyageurs, respectively.

Appendix A. MPCA's Regional Haze SIP Technical Support Document contains greater detail on the contribution assessment The following sections 2.2.2 and 2.2.3 focus on the contribution assessment results that fulfill the SIP requirements.

2.2.2. Minnesota's impact on Class I areas

As anticipated, Minnesota has the greatest visibility impact on the Class I areas within the State—Boundary Waters and Voyageurs—with lesser visibility impact on the two Michigan Class I areas, Isle Royale and Seney. Visibility impacts to the Class I areas in other states are unremarkable, except it is interesting that Minnesota has slightly more than 2.5 percent visibility impact at Mammoth Cave in Kentucky. Mammoth Cave is the furthest distance (828 km) from Minnesota of all the Class I areas assessed. It is located to the southeast of Minnesota and perhaps more of the impaired days at Mammoth Cave are in the cooler months this implementation period than in the first implementation period.

Table 11. Minnesota contribution to 2028 nitrate and sulfate extinction at select Class I areas[60]

Class I area	Monitor site abbreviation	Monitor location		Distance of monitor from Minnesota boundary (km)	Minnesota contribution to visibility (%)
		Latitude	Longitude		
Boundary Waters Canoe Area Wilderness	BOWA1	47.9466	-91.4955	0	16.2
Voyageurs National Park	VOYA2	48.4126	-92.8286	0	17.6
Isle Royale National Park	ISLE1	47.4596	-88.1491	117	8.2
Seney Wilderness Area	SENE1	46.2889	-85.9503	329	4.3
Lostwood Wilderness	LOST1	48.6419	-102.4022	381	0.5
Badlands Wilderness	BADL1	43.7435	-101.9412	442	1.2
Theodore Roosevelt National Park	THRO1	46.8948	-103.3777	489	1.7
Mingo Wilderness Area	MING1	36.9717	-90.1432	731	1.6
Hercules-Glades Wilderness Area	HEGL1	36.6138	-92.9221	765	1.8
Mammoth Cave National Park	MACA1	37.1318	-86.1479	828	2.6

[60] *Does not include contribution from fire.*

2.2.3. States impacting Minnesota's Class I areas

Emissions sources located outside the boundary of the modeling domain, from the direction of Canada, carry a very significant portion of the visibility impact at Boundary Waters (37.7%) and Voyageurs (40.2%). This is a much higher percentage than the first implementation period at Boundary Waters (11%) and Voyageurs (15%) as shown in Table 9 above. The portion of Canada within the modeling domain is significant contributor at Boundary Waters (7%) and Voyageurs (10%). The remainder of Canada falls outside the boundary of the modeling domain.

Source apportionment techniques can only account for the total contribution of boundary conditions to the overall visibility conditions, which accounts for the conservation of mass in the apportionment modeling. Broadly assuming all the impacting sources are in Canada, total impact estimates from Canada would be Boundary Waters 44.7% (37.7% plus 7.0%) and Voyageurs 50.2% (40.2% plus 10.0%) as shown in Table 12. However, that can't be determined without further study. Some of the contribution from outside the boundary could be from U.S. air traveling outside the boundary then re-entering.

Minnesota along with other states are still culpable for visibility impacts at Boundary Waters and Voyageurs. Table 12 contains the percent contribution to visibility at Boundary Waters and Voyageurs for each region in the assessment.

Table 12. Region contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas[61]

Region name	Boundary Waters		Voyageurs	
	Distance of region boundary to monitor (km)	Region contribution to visibility (%)	Distance of region boundary to monitor (km)	Region contribution to visibility (%)
Boundary of model domain	432	37.7	385	40.2
Minnesota	0	16.2	0	17.6
Canada/Mexico	12 / 2,190	7.0	10 / 2,176	10.0
North Dakota	404	4.8	314	5.9
Central Midwest[62]	934	4.6	955	3.7
Iowa	494	4.3	546	4.1
Nebraska	715	3.9	706	3.5
West[63]	446	3.9	395	3.0
Wisconsin	113	3.6	194	1.5
Missouri	815	3.5	869	2.8
Illinois	608	2.6	678	1.7
Texas	1,451	1.5	1,447	1.3
Indiana	760	1.0	853	0.9
Southeast[64]	1,118	1.0	1,216	0.8

[61] *Does not include contribution from fire (2.8 % at Boundary Waters and 1.0 % at Voyageurs)*
[62] ***Central Midwest** region comprised of Arkansas, Kansas, Louisiana, and Oklahoma.*
[63] ***West** region comprised of Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, South Dakota, Utah, Washington, and Wyoming.*
[64] ***Southeast** region comprised of Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.*

Region name	Boundary Waters		Voyageurs	
	Distance of region boundary to monitor (km)	Region contribution to visibility (%)	Distance of region boundary to monitor (km)	Region contribution to visibility (%)
Northeast[65]	872	0.9	977	1.1
Michigan	170	0.4	274	0.8
Water bodies	64	0.2	170	0.2

In the first implementation period, MPCA chose a five percent contribution threshold for determining significant contribution to visibility impacts at each Class I area. For the second implementation period, MPCA has chosen a 3.5% contribution threshold.

A 3.5% contribution threshold accounts for roughly 80% of the total contribution to visibility impairment at Boundary Waters and Voyageurs. The figure was derived by sorting the region percent contributions in descending order and calculating the cumulative percent until reaching 80%. The boundary of the model domain is included in the cumulative percent. The Central Midwest and West regions are excluded from the cumulative percent because those regions are an aggregation of multiple states, and it would be unlikely for any one state individually to appear as high on the sorted list.

Minnesota, Canada, North Dakota, Iowa, Nebraska, Wisconsin, and Missouri are identified as the most culpable regions contributing to visibility impairment in one or both Class I areas in Minnesota.

In the August 2019 Guidance, U.S. EPA says a state with a Class I area may advise another state that it considers its Class I area(s) to be affected by emissions from the other state.[66] While each state is responsible for its determination of what Class I areas may be affected by its emissions, U.S. EPA states that this is a potential area for interstate consultation. 40 CFR § 51.308(f)(2)(ii)(C) specifies the requirements for documenting interstate consultations and describing the actions taken to resolve any disagreements on the emission reduction measures needed to make reasonable progress:

> *In any situation in which a State cannot agree with another State on the emission reduction measures necessary to make reasonable progress in a mandatory Class I Federal area, the State must describe the actions taken to resolve the disagreement. In reviewing the State's implementation plan, the Administrator will take this information into account in determining whether the plan provides for reasonable progress at each mandatory Class I Federal area that is located in the State or that may be affected by emissions from the State. All substantive interstate consultations must be documented.*

Other than adjusting the 2064 endpoint of the glidepath to account for international impacts, Minnesota has no recourse to address visibility impacts from Canada to Boundary Waters and Voyageurs. As discussed in Section 2.7, MPCA does not seek U.S. EPA approval to adjust the 2064 endpoint this implementation period because observation data for both Boundary Waters and Voyageurs are below the glidepath and well under way to meet the unadjusted 2064 end point at this time.

Given that Minnesota is a major contributor to visibility impairment at its own Class I areas, the MPCA believes that the measures taken to reach the 2028 reasonable progress goals set for the Boundary Waters and Voyageurs, discussed in Section 2.5, are sufficient to account for Minnesota's share of

[65] ***Northeast*** *region comprised of Connecticut, Delaware, District of Columbia, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Vermont.*
[66] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 52-53

emissions reductions needed to meet the reasonable progress goal at any other Class I area that Minnesota may impact.

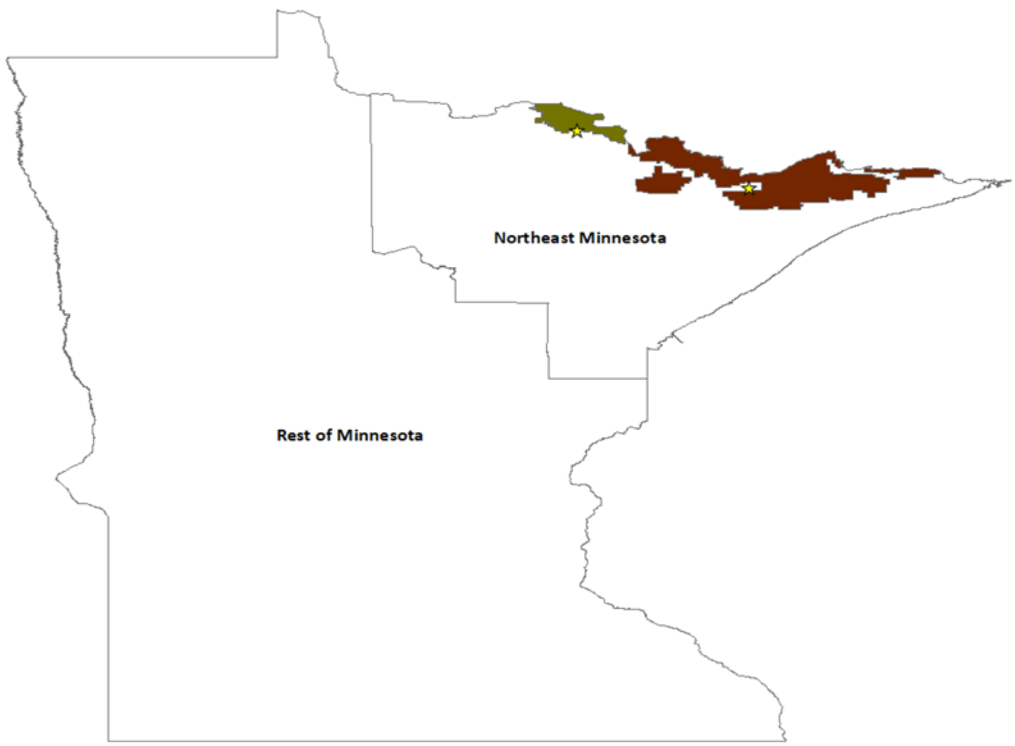
No states have notified Minnesota that they identified Minnesota emissions as reasonably anticipated to contribute to visibility impairment at Class I areas within their borders. No states have asked Minnesota to undertake specific emissions reductions necessary to make reasonable progress. Further information regarding consultation with specific states is provided in Section 2.9.1. Consultation with states.

Sector contributions to sulfate and nitrate visibility impairment by the most culpable regions. MPCA has more thoroughly assessed the contributions of regions over the 3.5% threshold by evaluating the NO_X and SO_2 emissions from these regions and the resultant contributions by sector grouping. Minnesota, Canada, North Dakota, Iowa, Nebraska, Wisconsin, and Missouri are identified as the most culpable regions contributing to visibility impairment in one or both Class I areas in Minnesota. In addition to the anthropogenic contribution from each region, the MPCA includes natural contribution for comparison. Additional detail regarding contribution to sulfate and nitrate visibility impairment from these regions is available in Appendix A. MPCA's Regional Haze SIP Technical Support Document.

Minnesota. Minnesota overall contributes mostly nitrate, roughly two thirds, to visibility impairment at Boundary Waters and Voyageurs and corresponding statewide NO_X emissions are more than 6.5 times higher than statewide SO_2 emissions. Each of the sector groups contribute mostly nitrate to visibility impairment, except for EGUs which contribute mostly sulfate to its portion of visibility impairment. The preferential formation of sulfate over nitrate in the atmosphere likely has a role in the non-linear contribution of sulfate from electric generating units.

The MPCA also separated contributions from "Northeast Minnesota" and the "Rest of Minnesota", shown in Figure 9. Northeast Minnesota comprises the six counties, Carlton, Cook, Itasca, Koochiching, Lake, and St. Louis. These counties encompass the entire boundaries of both Boundary Waters and Voyageurs. In both the first and second implementation periods, the MPCA has included in its SIP the "Northeast Minnesota Plan" for facilities in the Northeast Minnesota counties to assure no backsliding on NO_X and SO_2 emissions in the region. The Northeast Minnesota Plan is described in more detail in Section 2.5.7.

Figure 9. "Northeast Minnesota" and "Rest of Minnesota" regions



Northeast Minnesota. The Northeast Minnesota region overall contributes mostly nitrate, roughly two thirds, to visibility impairment at Boundary Waters and Voyageurs and corresponding regional NO_X emissions are nearly 6 times higher than statewide SO_2 emissions. Each of the sector groups contribute mostly nitrate to visibility impairment, except for EGUs which contribute mostly sulfate to its portion of visibility impairment. The preferential formation of sulfate over nitrate in the atmosphere likely has a role in the non-linear contribution of sulfate from electric generating units. In Northeast Minnesota the industry sector grouping is by far the most significant contributor to impairment at 4.7% of the region total at 6.5% at Boundary Waters and 7.3% at Voyageurs. The EGU sector contributes 1.3% of the region total at Voyageurs. Each of the remaining sector groupings make up less than 1% of the region total at either Boundary Waters or Voyageurs.

Rest of Minnesota. The Rest of Minnesota region overall contributes mostly nitrate, roughly two thirds, to visibility impairment at Boundary Waters and Voyageurs and corresponding regional NO_X emissions are nearly 7 times higher than statewide SO_2 emissions. Each of the sector groups contribute mostly nitrate to visibility impairment, except for EGUs which contribute mostly sulfate to its portion of visibility impairment. In the Rest of Minnesota vehicles are the most significant contributor to visibility impairment at around 3% of the region total at Boundary Waters and Voyageurs. The remaining anthropogenic sector groupings are close at from about 2.5% contribution for the combined area, oil & gas and residential wood combustion sector grouping, around 2.0% contribution for EGUs, to about 1.5% contribution for industry. The industry sector grouping is close to the contribution of nitrate from natural sources at 0.9% and 1.2% at Boundary Waters and Voyageurs, respectively.

Table 13 contains the percent contribution of total sulfate and nitrate visibility impairment for each sector group, a percent breakdown of sulfate and nitrate, and the associated 2028 NO_X and SO_2 emissions used in the analysis.

Table 13. Minnesota sector contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas

Minnesota Sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Minnesota[67]						
Region total	16.2	17.6			180,940	27,219
Industry	6.2	6.3			36,000	10,000
Vehicle	3.5	3.7			62,200	907
EGU	2.6	3.5			12,200	12,000
Area + Oil/gas + RWC	2.9	2.7			28,040	4,312
Natural	1.0	1.4			42,500	--
Northeast Minnesota Counties (Carlton, Cook, Itasca, Koochiching, Lake, and St. Louis)						
Region total	6.5	7.3			33,690	5,663
Industry	4.7	4.7			20,900	3,440
EGU	0.8	1.3			4,180	1,810
Vehicle	0.6	0.7			5,470	43
Area + Oil/gas + RWC	0.3	0.4			1,310	370
Natural	0.1	0.1			1,830	--

[67] *The sub-region emission totals from Northeast Minnesota and Rest of Minnesota do not exactly add-up to the total for the entire state. The MPCA suspects a mathematics issue, most likely related to rounding, by MPCA that will be investigated further during the public comment period.*

Minnesota Sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Rest of Minnesota						
Region total	9.7	10.3			148,120	21,600
Vehicle	2.9	3.1			57,200	880
Area + Oil/gas + RWC	2.5	2.4			26,700	3,950
EGU	1.8	2.2			8,020	10,200
Industry	1.5	1.5			15,200	6,570
Natural	0.9	1.2			41,000	--

In the first implementation period, Northeast Minnesota contributed more than half of the State total percent contribution of light extinction at Boundary Waters and just under half of the percent contribution of light extinction at Voyageurs. In the second implementation period, Northeast Minnesota contributes about 40% visibility impairment at both Boundary Waters and Voyageurs. With 60% of the visibility impairment from Minnesota attributed to the rest of the state, the modeling suggests the need for additional focus on vehicles in the third implementation period.

Table 14 contains a breakdown of the emissions into less aggregated sector groups for the second implementation period and includes the emissions change from baseline for the whole state. In Minnesota large reductions in NO_X emissions of around 66,200 tons from vehicles (on-road and off-road) were accounted for between 2016 and 2028. Even so, vehicles make up about 62,200 tons of NO_X in 2028. In comparison, the EGU and industry sector groups combined make up about 48,200 tons of NO_X and 22,000 tons of SO_2 in 2028.

Table 14. Minnesota NO_X and SO_2 emissions change from baseline by sector group

Sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
Area	22,500	22,000	-577	3,010	3,000	-6.62
EGU	19,800	12,200	-7,570	16,900	12,000	-4,950
Industry	43,500	36,000	-7,500	11,500	10,000	-1,480
Oil/gas	2,840	2,690	-152	152	152	0.004
On-road	68,400	22,700	-45,700	403	198	-205
Off-road	60,000	39,500	-20,500	361	709	348
RWC	3,440	3,350	-96.1	1,360	1,160	-197
Fire	2,620	2,620	0.00	1,790	1,790	0.00
Natural	42,500	42,500	0.00			

North Dakota. North Dakota overall contributes mostly nitrate to visibility impairment at Boundary Waters (60%) and Voyageurs (53%) and corresponding statewide NO_X emissions are more than 3 times higher than statewide SO_2 emissions. Each of the sector groups contribute mostly nitrate to visibility impairment, except for EGUs which contribute mostly sulfate to its portion of visibility impairment. The preferential formation of sulfate over nitrate in the atmosphere likely has a role in the non-linear contribution of sulfate from EGUs.

Table 15 contains the percent contribution of total sulfate and nitrate visibility impairment for each sector group, a percent breakdown of sulfate and nitrate, and the associated 2028 NO_X and SO_2 emissions used in the analysis.

Table 15. North Dakota sector contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas

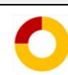
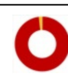
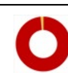
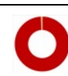
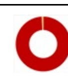
North Dakota sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Region total	4.8	5.9			151,228	49,629
EGU	2.4	2.5			33,600	38,000
Area + Oil/gas + RWC	1.1	1.4			34,048	9,444
Vehicle	0.7	1.0			29,470	165
Natural	0.4	0.6			50,500	--
Industry	0.2	0.3			3,610	2,020

Table 16 contains a breakdown of the emissions into less aggregated sector groups and includes the emissions change from baseline. In North Dakota large reductions in NO_X emissions of around 32,200 tons from vehicles (on-road and off-road) were accounted for between 2016 and 2028. Vehicles make up about 29,800 tons of NO_X in 2028. The EGU and industry sector groups combined make up about 37,200 tons of NO_X and 40,000 tons of SO_2 in 2028. The oil and gas sector NO_X emissions in the modeling are projected to increase 12,500 tons to 32,700 tons in 2028. Oil and gas sector SO_2 emissions are also projected to increase nearly 3,000 tons to 9,240 tons in 2028. North Dakota actions to limit emissions from EGUs and perhaps oil & gas are most likely to lessen visibility impacts at Boundary Waters and Voyageurs.

Table 16. North Dakota NO_X and SO_2 emissions change from baseline by sector group

North Dakota sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
Area	1,210	1,210	1.32	174	174	0.293
EGU	38,400	33,600	-4,850	47,100	38,000	-9,170
Industry	3,640	3,610	-32.5	2,220	2,020	-204
Oil/gas	20,200	32,700	12,500	6,280	9,240	2,960

North Dakota sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
On-road	22,000	8,270	-13,700	75.2	54.3	-20.9
Off-road	39,700	21,200	-18,500	104	111	6.33
RWC	133	138	5.28	32.4	30.1	-2.25
Fire	2,470	2,470	0.00	1,170	1,170	0.00
Natural	50,500	50,500	0.00			

Iowa. Iowa overall contributes mostly nitrate to visibility impairment at Boundary Waters (60%) and Voyageurs (53%) and corresponding statewide NO_X emissions are more than 3 times higher than statewide SO_2 emissions. Each of the sector groups contribute mostly nitrate to visibility impairment, except for EGUs which contribute mostly sulfate to its portion of visibility impairment. The preferential formation of sulfate over nitrate in the atmosphere likely has a role in the non-linear contribution of sulfate from EGUs.

Table 17 contains the percent contribution of total sulfate and nitrate visibility impairment for each sector group, a percent breakdown of sulfate and nitrate, and the associated 2028 NO_X and SO_2 emissions used in the analysis.

Table 17. Iowa sector contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas

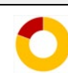
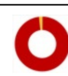
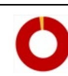
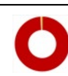
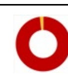
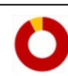
Iowa sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Region total	4.3	4.1			156,722	36,120
EGU	1.8	1.9			22,300	28,500
Vehicle	1.0	0.8			46,600	382
Natural	0.6	0.6			59,800	--
Industry	0.5	0.4			13,600	6,680
Area + Oil/gas + RWC	0.4	0.3			14,422	558

Table 18 contains a breakdown of the emissions into less aggregated sector groups and includes the emissions change from baseline. In Iowa large reductions in NO_X emissions of around 53,700 tons from vehicles (on-road and off-road) were accounted for between 2016 and 2028. Vehicles make up about 46,600 tons of NO_X in 2028. The EGU and industry sector groups combined make up about 35,900 tons of NO_X and 35,200 tons of SO_2 in 2028. Emissions reductions between 2016 and 2028 from electric generating units are only 427 tons of NO_X and 4,050 tons of SO_2. Iowa actions to limit emissions from EGUs and perhaps vehicles are most likely to lessen visibility impacts at Boundary Waters and Voyageurs.

Table 18. Iowa NO_X and SO_2 emissions change from baseline by sector group

Iowa sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
Area	9,110	8,940	-173	422	428	6.11
EGU	22,700	22,300	-427	32,600	28,500	-4,050
Industry	15,200	13,600	-1,590	6,910	6,680	-227
Oil/gas	5,060	4,890	-178	5.30	5.30	0.00
On-road	52,100	18,400	-33,700	294	132	-162
Off-road	48,200	28,200	-20,000	138	250	111
RWC	594	592	-2.15	162	125	-37.1
Fire	1,420	1,420	0.00	749	749	0.00
Natural	59,800	59,800	0.00			

Nebraska. Nebraska overall contributes mostly nitrate to visibility impairment at Boundary Waters (51%) and Voyageurs (60%) and corresponding statewide NO_X emissions are 2.75 times higher than statewide SO_2 emissions. Each of the sector groups contribute mostly nitrate to visibility impairment, except for EGUs which contribute mostly sulfate to its portion of visibility impairment. The preferential formation of sulfate over nitrate in the atmosphere likely has a role in the non-linear contribution of sulfate from electric generating units.

Table 19 contains the percent contribution of total sulfate and nitrate visibility impairment for each sector group, a percent breakdown of sulfate and nitrate, and the associated 2028 NO_X and SO_2 emissions used in the analysis.

Table 19. Nebraska Sector contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas

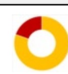
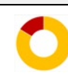
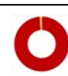
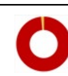
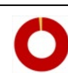
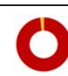
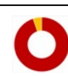
Nebraska sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Region total	3.9	3.5			163,169	59,187
EGU	2.4	2.4			23,200	57,000
Vehicle	0.8	0.5			51,200	204
Industry	0.2	0.2			7,270	1,840
Natural	0.4	0.2			74,700	--
Area + Oil/gas + RWC	0.2	0.1			6,799	143

Table 20 contains a breakdown of the emissions into less aggregated sector groups and includes the emissions change from baseline. In Nebraska large reductions in NO_X emissions of around 47,300 tons from vehicles (on-road and off-road) were accounted for between 2016 and 2028. Vehicles make up about 51,200 tons of NO_X in 2028. The EGU and industry sector groups combined make up about 30,500 tons of NO_X and 68,800 tons of SO_2 in 2028. In the modeling, emissions increased between 2016 and 2028 from EGUs by 2,400 tons of NO_X and 5,260 tons of SO_2. Nebraska actions to limit emissions from EGUs are most likely to lessen visibility impacts at Boundary Waters and Voyageurs.

Table 20. Nebraska NO_X and SO_2 emissions change from baseline by sector group

Nebraska sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
Area	2,830	2,830	1.92	87.7	88.0	0.333
EGU	20,800	23,200	2,400	51,700	57,000	5,260
Industry	7,270	7,270	-2.73	1,840	1,840	-6.83
Oil/gas	4,140	3,690	-445	3.66	3.64	-0.02
On-road	37,300	13,700	-23,600	194	92.4	-102
Off-road	61,200	37,500	-23,700	116	112	-3.84
RWC	277	279	1.98	66.5	51.7	-14.8
Fire	1,610	1,610	0.00	770	770	0.00
Natural	74,700	74,700	0.00			

Wisconsin. Wisconsin overall contributes mostly nitrate to visibility impairment at Boundary Waters (76%) and Voyageurs (65%) and corresponding statewide NO_X emissions are nearly 5 times higher than statewide SO_2 emissions. Sector groups with emissions not routed through stacks contribute mostly nitrate to visibility impairment. EGUs and industry contribute mostly nitrate to visibility impairment at Boundary Waters and mostly sulfate to visibility impairment at Voyageurs. The preferential formation of sulfate over nitrate in the atmosphere likely has a role in the non-linear contribution of sulfate from industry and EGUs.

Table 21 contains the percent contribution of total sulfate and nitrate visibility impairment for each sector group, a percent breakdown of sulfate and nitrate, and the associated 2028 NO_X and SO_2 emissions used in the analysis.

Table 21. Wisconsin Sector contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas

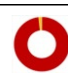
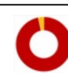
Wisconsin sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Region total	3.6	1.5			129,829	26,611
Industry	1.2	0.6			22,800	19,400
Vehicle	1.2	0.4			47,700	496
Area + Oil/gas + RWC	0.6	0.2			21,229	2,015
EGU	0.3	0.2			13,500	4,700
Natural	0.3	0.2			24,600	--

Table 22 contains a breakdown of the emissions into less aggregated sector groups and includes the emissions change from baseline. In Wisconsin large reductions in NO_X emissions of around 66,000 tons from vehicles (on-road and off-road) were accounted for between 2016 and 2028. Vehicles make up about 47,700 tons of NO_X in 2028. The EGU and industry sector groups combined make up about 36,300 tons of NO_X and 24,100 tons of SO_2 in 2028. In the modeling, emissions reductions between 2016 and 2028 from industrial facilities are only 307 tons of NO_X and 1,150 tons of SO_2. Wisconsin actions to limit emissions from industrial facilities and perhaps vehicles are most likely to lessen visibility impacts at Boundary Waters and Voyageurs.

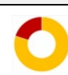
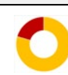
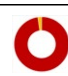
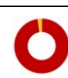
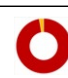
Table 22. Wisconsin NO_X and SO_2 emissions change from baseline by sector group

Wisconsin sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
Area	20,100	19,500	-652	1,730	1,750	21.4
EGU	16,100	13,500	-2,540	13,000	4,700	-8,260
Industry	23,100	22,800	-307	20,500	19,400	-1,150
Oil/gas	535	619	83.1	0.043	0.065	0.022
On-road	79,600	25,200	-54,400	410	227	-183
Off-road	34,100	22,500	-11,600	172	269	96.8
RWC	1,100	1,110	12.1	320	265	-54.5
Fire	765	765	0.00	407	407	0.00
Natural	24,600	24,600	0.00			

Missouri. Missouri overall contributes mostly nitrate to visibility impairment at Boundary Waters (56%) and Voyageurs (56%) and corresponding statewide NO_X emissions are less than 2 times higher than statewide SO_2 emissions. Each of the sector groups contribute mostly nitrate to visibility impairment, except for EGUs which contribute mostly sulfate to its portion of visibility impairment.

Table 23 contains the percent contribution of total sulfate and nitrate visibility impairment for each sector group, a percent breakdown of sulfate and nitrate, and the associated 2028 NO_X and SO_2 emissions used in the analysis.

Table 23. Missouri Sector contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas

Missouri sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Region total	3.5	2.8			204,531	109,547
EGU	1.6	1.3			33,200	95,600
Vehicle	0.9	0.7			75,600	848
Industry	0.4	0.3			21,000	12,200
Natural	0.3	0.3			55,400	--

Missouri sector group	Contribution to visibility (%)		Pollutant contribution (%) ■ NH4NO3 ■ NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Area + Oil/gas + RWC	0.3	0.2			19,331	899

Table 24 contains a breakdown of the emissions into less aggregated sector groups and includes the emissions change from baseline. In Missouri large reductions in NO_X emissions of around 92,700 tons from vehicles (on-road and off-road) were accounted for between 2016 and 2028. Vehicles make up about 75,600 tons of NO_X in 2028. The EGU and industry sector groups combined make up about 54,200 tons of NO_X and 107,000 tons of SO_2 in 2028. Emissions reductions between 2016 and 2028 from EGUs are 24,200 tons of NO_X and 4,130 tons of SO_2. Missouri actions to limit emissions from EGUs and perhaps vehicles are most likely to lessen visibility impacts at Boundary Waters and Voyageurs.

Table 24. Missouri NO_X and SO_2 emissions change from baseline by sector group

Missouri sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
Area	14,600	14,000	-569	671	670	-0.92
EGU	57,400	33,200	-24,200	99,800	95,600	-4,130
Industry	21,000	21,000	3.84	13,000	12,200	-738
Oil/gas	4,590	4,380	-212	4.33	4.31	-0.02
On-road	108,000	38,800	-69,300	588	309	-280
Off-road	60,200	36,800	-23,400	260	539	279
RWC	949	951	1.62	276	225	-50.5
Fire	12,700	12,700	0.00	6,270	6,270	0.00
Natural	55,400	55,400	0.00			

Canada. Canadian emissions provided by U.S. EPA to the MPCA did not distinguish between EGUs and industrial facilities, and MPCA decided to put them all in the industry sector group for source apportionment modeling. The vehicle sector group only includes on-road vehicles. Off-road vehicles came combined with area sources in the area sector group. Canada only has four sector groups, industry, area, natural and vehicle. Overall Canada contributes mostly sulfate to visibility impairment at Boundary Waters (59%) and Voyageurs (51%) and corresponding region total emissions of NO_X are more than 1.5 times higher than region total emissions of SO_2. Each of the sector groups contribute mostly nitrate to visibility impairment, except for industry (including EGUs) which contribute mostly sulfate to its portion of visibility impairment.

Table 25 contains the percent contribution of total sulfate and nitrate visibility impairment for each sector group, a percent breakdown of sulfate and nitrate, and the associated 2028 NO_X and SO_2 emissions used in the analysis.

Table 25. Canada Sector contribution to 2028 nitrate and sulfate extinction at Minnesota Class I areas

Canada Sector group	Contribution to visibility (%)		Pollutant contribution (%) NH4NO3 NH4SO4		Annual emissions (tons)	
	Boundary Waters	Voyageurs	Boundary Waters	Voyageurs	NO_X	SO_2
Region total	7.0	10.0			618,000	386,035
Industry + EGU	5.3	6.8			199,000	372,000
Area	0.9	1.7			190,000	13,500
Natural	0.4	0.8			114,000	--
Vehicle	0.4	0.7			115,000	535

Canada emissions are distributed across the entire northern border of the United States. To get a better understanding of the emissions impacting Boundary Waters and Voyageurs, the MPCA divided the emissions summary into West Canada and East Canada. The border between Manitoba and Ontario north of Minnesota serves as the dividing line.

Table 26 contains a breakdown of the emissions into less aggregated sector groups and includes the emissions change from baseline. Canada experienced large reductions in NO_X emissions of around 157,000 tons (55,300 tons West, 102,000 tons East) from vehicles (on-road vehicles only) that were accounted for between 2016 and 2028. Vehicles make up about 115,000 tons (35,700 tons West, 79,300 tons East) of NO_X in 2028. The industry sector group (including EGUs) makes up about 199,000 tons (74,900 tons West, 124,000 tons East) tons of NO_X and about 372,000 tons (96,700 tons West, 275,000 tons East) of SO_2 in 2028. Emissions reductions between 2016 and 2028 from industry (including EGUs) are about 34,000 tons (43,500 tons reduction West, 9,610 tons increase East) of NO_X and about 140,000 tons (28,600 tons West, 111,000 tons East) of SO_2. The area (including off-road vehicles) sector group makes up about 190,000 tons NO_X in 2028. Emissions reductions between 2016 and 2028 from area (including off-road vehicles) are about 74,500 tons (31,600 tons West, 42,900 tons East) of NO_X. Canada actions to limit emissions from industry (including EGUs) and perhaps area sources are most likely to lessen visibility impacts at Boundary Waters and Voyageurs.

Table 26. Canada NO_X and SO_2 emissions change from baseline by sector group

Canada sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
West Canada						
Area	95,600	64,000	-31,600	6,410	6,280	-125
Industry + EGU	118,000	74,900	-43,500	125,000	96,700	-28,600
On-road	91,100	35,700	-55,400	238	113	-125
Fire	2,920	2,920	0.00	1,490	1,490	0.00
Natural	78,300	78,300	0.00			

Canada sector group	NO_X emissions (tons)			SO_2 emissions (tons)		
	2016	2028	Difference	2016	2028	Difference
East Canada						
Area	169,000	126,000	-42,900	7,460	7,220	-238
Industry + EGU	114,000	124,000	9,610	386,000	275,000	-111,000
On-road	182,000	79,300	-102,000	974	422	-553
Fire	4,580	4,580	0.00	1,940	1,940	0.00
Natural	35,700	35,700	0.00			

Contribution analysis summary. The region and sector contribution analysis of sulfate and nitrate at Boundary Waters and Voyageurs supports the main statements MPCA posited at the beginning of Section 2.2, before examining the model contribution data, with a few modifications.

- Minnesota continues to be the largest state contributor to visibility impairment at Boundary Waters and Voyageurs.
- NO_X emission reductions are needed.
- Boundary Waters and Voyageurs may benefit from emission reductions in other regions or states located to the West and Northwest but also from other directions, in the following order of importance: Canada, North Dakota, Iowa, Nebraska, Wisconsin and Missouri.

After examining the results, MPCA adds that SO_2 emission reductions especially from electric generating units in other states likely may lessen visibility impacts at Boundary Waters and Voyageurs. In this scenario, reductions of both species should occur together. The preferential formation of sulfate over nitrate in the atmosphere likely has a role in the non-linear contribution of sulfate to visibility impairment. Reductions of sulfate could free up ammonia to interact with available NO_X to form additional nitrate.

Most non-Minnesota state contributors over 3.5% threshold (North Dakota, Iowa, Nebraska, and Missouri) contribute most from EGUs except for Wisconsin. Like Minnesota, Wisconsin's top two sector contributors to sulfate and nitrate extinction at Boundary Waters and Voyageurs, in order of importance, are industry and vehicles.

2.3. Step 3 - Selection of sources for analysis

The Regional Haze Rule requires states to select emission sources for analysis of emission control measures, include a description of the criteria used to make those selections, and consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. All states, including those without Class I areas, are required to select sources for analysis and determine what emission controls measures are necessary to make reasonable progress at the state's own Class I areas and Class I areas in other states.

In the first regional haze implementation period, the focus of the Regional Haze Rule was on establishing Best Available Retrofit Technology (BART) for certain older sources and reasonable progress towards national visibility goals. The selection of sources in the first implementation period was based on whether the emission source was subject to BART under section 169A of the Clean Air Act.

In the second regional haze implementation period the focus on making reasonable progress remains, but there are no BART requirements that specify which sources must be evaluated for emission control measures. The required content for what sources should be considered and documenting how a state selects sources for analysis in the second implementation period is specified in 40 CFR § 51.308(f)(2)(i).

The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.

U.S. EPA provides additional information regarding how a state selects emissions sources for analysis of emission control measures in its August 2019 Guidance. The guidance describes that a state is not required to evaluate all sources of emissions in each implementation period, which is consistent with the iterative planning process that is setup by the Regional Haze Rule.[68] Therefore, it is reasonable and permissible for a state to address some sources in the second implementation period and other sources in later periods.

The guidance also describes factors that may be considered when selecting sources for analysis. However, the guidance and Regional Haze Rule do not explicitly list factors that a state must or may not consider when selecting sources for analysis. Additionally, the guidance states that the selection of a source does not necessarily mean that emission control measures will ultimately be required for that source.[69]

In general, U.S. EPA ties the selection of sources to the statutory requirement to make reasonable progress towards natural visibility. In lieu of an explicit list of factors to consider, the guidance states that a state must reasonably choose factors and apply them in a reasonable way in selecting a set of sources to analyze.[70] U.S. EPA does provide several examples of types of information that may be useful in selecting a set of sources for analysis, including:

- Baseline source emissions.
- Estimated visibility impacts (or surrogate metrics for visibility impacts).
- Existing control measures.
- The four statutory factors listed in in 40 CFR § 51.308(f)(2)(i).
- The five required additional factors listed in 40 CFR § 51.308(f)(2)(iv).
- Other factors that are reasonable to consider.

Overall, U.S. EPA recommends that the documentation and description of the criteria the state used to determine the sources it evaluated for potential controls provide, “both a summary of the state’s source selection approach and a detailed description of how the state used technical information to select a reasonable set of sources for an analysis of control measures for the second implementation period.”[71]

Based on the Regional Haze Rule, U.S. EPA’s August 2019 Guidance, and in alignment with other LADCO member states, the MPCA conducted a screening analysis for stationary sources to determine which sources would be selected. Ultimately, the MPCA selected sources that represent roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the screening analysis for Boundary Waters and Voyageurs. The MPCA sent request for information (RFI) letters to these facilities requesting that they prepare and submit a four-factor analysis for the identified emission units that examined potential control measures to reduce emissions of the identified pollutant(s). For Minnesota sources, this initial screening analysis represents emission units at taconite processing facilities, pulp/paper mills, sugar manufacturing facilities, and electric power generation facilities. The table below

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[68] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 9.
[69] *See id.*
[70] *See id.*
[71] *Id.* at 27.

summarizes which facilities and emission units that the MPCA requested to conduct a four-factor analysis.

Table 27. Four-factor analyses requested by MPCA

Facility name	Emission unit	Emission unit ID (Tempo)	Emission unit ID (Delta)	Pollutants
American Crystal Sugar - Crookston	Boiler 1	EQUI 14	EU 001	NO_X, SO_2
	Boiler 2	EQUI 15	EU 002	NO_X, SO_2
	Boiler 3	EQUI 16	EU 003	NO_X, SO_2
American Crystal Sugar - East Grand Forks	Boiler 1	EQUI 18	EU 001	NO_X, SO_2
	Boiler 2	EQUI 19	EU 002	NO_X, SO_2
Boise White Paper	Recovery Furnace	EQUI 9	EU 320	NO_X
	Boiler 1	EQUI 15	EU 420	NO_X
	Boiler 2	EQUI 16	EU 430	NO_X, SO_2
Cleveland Cliffs Minorca Mine Inc.	Indurating Machine	EQUI 38	EU 026	NO_X, SO_2
Hibbing Public Utilities Commission	Boiler No. 1A	EQUI 1	EU 001	NO_X, SO_2
	Boiler No. 2A	EQUI 2	EU 002	NO_X, SO_2
	Boiler No. 3A	EQUI 3	EU 003	NO_X, SO_2
	Wood Fired Boiler	EQUI 7	EU 007	NO_X
Hibbing Taconite Company	Indurating Furnace Line 1	EQUI 95	EU 020	NO_X, SO_2
	Indurating Furnace Line 2	EQUI 96	EU 021	NO_X, SO_2
	Indurating Furnace Line 3	EQUI 97	EU 022	NO_X, SO_2
Minnesota Power - Boswell Energy Center	Unit 1	EQUI 82	EU 001	NO_X, SO_2
	Unit 2	EQUI 83	EU 002	NO_X, SO_2
	Unit 3	EQUI 100	EU 003	NO_X, SO_2
	Unit 4	EQUI 85	EU 004	NO_X, SO_2
Minnesota Power - Taconite Harbor Energy	Boiler 1	EQUI 64	EU 001	NO_X, SO_2
	Boiler 2	EQUI 5	EU 002	NO_X, SO_2
Northshore Mining - Silver Bay	Power Boiler 1	EQUI 14	EU 001	NO_X, SO_2
	Power Boiler 2	EQUI 15	EU 002	NO_X, SO_2
	Furnace 11	EQUI 126 & 127	EU 100 & 104	NO_X, SO_2
	Furnace 12	EQUI 128 & 129	EU 110 & 114	NO_X, SO_2
Sappi Cloquet LLC	Power Boiler #9	EQUI 4	EU 004	NO_X, SO_2
	Recovery Boiler #10	EQUI 53	EU 005	NO_X
Southern Minnesota Beet Sugar Cooperative	Boiler 1	EQUI 17	EU 001	NO_X, SO_2
United Taconite LLC - Fairlane Plant	Line 1 Pellet Induration	EQUI 45	EU 040	NO_X, SO_2
	Line 2 Pellet Induration	EQUI 47	EU 042	NO_X, SO_2
US Steel Corporation - Keetac	Grate Kiln	EQUI 97	EU 030	NO_X, SO_2

Facility name	Emission unit	Emission unit ID		Pollutants
		(Tempo)	(Delta)	
US Steel Corporation - Minntac	Line 3 Rotary Kiln	EQUI 146	EU 225	NO_X, SO_2
	Line 4 Rotary Kiln	EQUI 279	EU 261	NO_X, SO_2
	Line 5 Rotary Kiln	EQUI 280	EU 282	NO_X, SO_2
	Line 6 Rotary Kiln	EQUI 3	EU 315	NO_X, SO_2
	Line 7 Rotary Kiln	EQUI 179	EU 334	NO_X, SO_2
Virginia Department of Public Utilities	Boiler 7	EQUI 2	EU 001	NO_X, SO_2
	Boiler 9	EQUI 3	EU 003	NO_X, SO_2
	Boiler 11	EQUI 16	EU 006	NO_X
Xcel Energy - Allen S. King	Boiler 1	EQUI 68	EU 001	NO_X, SO_2
Xcel Energy - Sherburne	Unit 1	EQUI 92	EU 001	NO_X, SO_2
	Unit 2	EQUI 93	EU 002	NO_X, SO_2
	Unit 3	EQUI 94	EU 003	NO_X, SO_2

The information provided by facilities in response to MPCA's request to prepare a four-factor analysis for the identified emission units is available in Appendix B. Four-Factor Analyses - Facility Responses. Additional detail regarding how the MPCA selected these sources for analysis, including how certain emission units were removed from further analysis, is provided in the following sections.

2.3.1. Determining which pollutants to consider

Both direct and precursor pollutants can impair visibility and come from a variety of sources, both natural and anthropogenic, including motor vehicles, electricity generation, industrial facilities, agriculture, and wildfires. U.S. EPA states in its August 2019 Guidance that it is generally reasonable for a state to focus on the largest contributors to anthropogenic visibility impairment from pollutants at the affected Class I area, subsequently selecting sources with emissions of those dominant pollutants and their precursors.[72]

Information provided in Section 2.1 led the MPCA to focus on evaluating sources of SO_2 and NO_X emissions in this implementation period as opposed to other components that make up only a small contribution to visibility impairment in comparison.

2.3.2. Estimating visibility impacts for source selection

U.S. EPA offers recommendations in its August 2019 Guidance on estimating visibility impacts from sources or source categories as part of the source selection step.[73] U.S. EPA further clarifies that while the guidance for source selection presumes the use of an air quality model to estimate visibility impacts, the Regional Haze Rule doesn't require states to develop estimates of individual source or source category visibility impacts or use an air quality model to do so. The guidance continues that reasonable surrogate metrics for visibility impact may be used instead, and the concepts and recommendations from the guidance can also be applied when selecting sources based on surrogate metrics.[74]

In lieu of conducting an air quality modeling analysis, the 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

[72] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 11.
[73] *See id*. at 16.
[74] *See id*. at 12.

kilometers (d) from the Class I areas. MPCA relied on the Q/d results created by the Lake Michigan Air Directors Consortium (LADCO) for industrial point sources using 2016 emissions inventory data with revisions made to account for certain facilities that were idled or operating at reduced capacity in 2016.[75] The emissions inventory data identified emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), ammonia (NH_3), and volatile organic compounds (VOCs). LADCO completed the Q/d calculations in March 2018 using the best available inventories at that time.[76] LADCO also provided a Technical Support Document (TSD) memo, dated June 17, 2021, that described the data and methods used by LADCO to screen emissions source impacts on Class I areas for this implementation period, see Appendix C. LADCO Documentation.[77]

Table 28 below provides a summary of facility emissions data (NO_X, SO_2, $PM_{2.5}$, NH_3, and VOCs) used in the Q/d Analysis for Minnesota, limited to facilities with total emissions of the identified pollutants greater than 100 tons per year and the emissions for the remaining sources summarized in one row for conciseness.

Table 28. Q/d Analysis emissions data

Facility name	Emissions data (tons)					
	NH_3	NO_X	$PM_{2.5}$	SO_2	VOC	Total
Xcel Energy - Sherburne Generating Plant	2.34	8,471.06	517.62	8,504.01	212.27	17,707.30
US Steel Corp - Minntac	20.13	6,366.17	1,777.45	1,149.45	160.05	9,473.25
Minnesota Power Inc - Boswell Energy Ctr	1.44	4,314.49	1,186.26	3,644.25	67.69	9,214.13
US Steel Corp - Keetac	0.00	5,009.00	411.22	533.00	42.22	5,995.44
Hibbing Taconite Co	0.00	4,313.00	527.15	737.00	42.61	5,619.76
United Taconite LLC - Fairlane Plant	0.05	3,742.84	411.66	275.16	39.41	4,469.11
Northshore Mining Co - Silver Bay	0.32	2,169.12	327.39	1,538.98	15.23	4,051.03
Cleveland Cliffs Minorca Mine Inc	0.00	3,234.63	166.97	96.95	24.07	3,522.62
Xcel Energy - Allen S King Generating Plant	72.64	1,394.56	141.86	1,515.03	84.31	3,208.40
Flint Hills Resources Pine Bend Refinery	31.02	1,262.37	230.64	718.30	531.54	2,773.87
Minneapolis-St Paul International Airport	0.00	2,114.56	60.03	241.17	336.32	2,752.07
American Crystal Sugar - Crookston	0.85	712.30	191.65	875.74	571.38	2,351.92
Southern Minnesota Beet Sugar Coop	87.88	1,053.38	98.96	831.99	8.41	2,080.62
American Crystal Sugar - East Grand Forks	1.02	680.63	168.02	1,005.68	139.47	1,994.83
Sappi Cloquet LLC	22.92	1,420.65	128.87	82.88	117.36	1,772.68

[75] *See infra* Appendix C. LADCO Documentation; LADCO Regional Haze 2018-2028 Planning Period TSD, at 30
[76] *See* U.S. EPA, THE NATIONAL EMISSIONS INVENTORY COLLABORATIVE 2016 ALPHA INVENTORY REPRESENTED THE BEST ESTIMATE OF 2016 POINT EMISSIONS AT THE TIME, https://www.epa.gov/air-emissions-modeling/2016v71-alpha-platform.
[77] *See infra* Appendix C. LADCO Documentation.

Facility name	Emissions data (tons)					
	NH_3	NO_X	$PM_{2.5}$	SO_2	VOC	Total
Otter Tail Power Co	0.08	331.81	75.99	940.55	4.05	1,352.47
Minnesota Power - Taconite Harbor Energy Center	0.47	343.01	24.87	931.96	9.92	1,310.23
American Crystal Sugar - Moorhead	1.03	518.74	116.71	373.62	259.56	1,269.65
Anchor Glass Container Corp	1.50	672.42	125.99	362.96	72.63	1,235.51
Boise White Paper LLC - Intl Falls	110.87	802.76	29.53	33.00	165.57	1,141.73
Saint Paul Park Refining Co LLC	7.39	527.83	35.87	79.80	378.79	1,029.68
Hibbing Public Utilities Commission	41.33	477.95	12.34	369.47	12.44	913.53
Andersen Corp	0.29	35.67	62.83	2.11	806.36	907.26
CHS Mankato	2.32	127.19	59.02	0.44	683.97	872.94
Blandin Paper Co/MN Power - Rapids Energy Center	83.88	432.70	33.42	61.01	261.55	872.57
Gopher Resource	0.61	97.45	23.51	667.68	1.98	791.23
Xcel Energy - Red Wing Generating Plant	0.18	675.30	2.34	88.10	0.11	766.03
CHS Fairmont	1.84	19.83	12.87	0.38	701.74	736.66
Virginia Department of Public Utilities	42.33	346.09	20.88	300.73	13.00	723.03
3M - Hutchinson Tape Manufacturing Plant	1.33	65.88	1.75	0.19	613.13	682.27
ADM - Mankato	0.76	123.88	8.64	134.55	398.79	666.63
Minnesota Power - Hibbard Renewable Energy Ctr	78.97	444.25	27.75	89.90	19.52	660.39
Xcel Energy - Key City/Wilmarth	0.05	634.20	2.28	20.40	0.08	657.01
Benson Power Biomass Plant	18.91	375.60	109.67	31.10	51.25	586.53
USG Interiors - Red Wing	0.01	67.74	46.83	404.12	32.00	550.70
Willmar Municipal Utilities	0.32	136.72	43.22	348.46	1.28	530.00
WestRock MN Corp	3.68	319.75	1.50	0.69	132.52	458.14
Great River Energy	0.00	416.40	19.39	19.95	0.92	456.66
Koda Energy LLC	0.32	289.45	20.33	138.87	1.27	450.24
Covanta Hennepin Energy Resource Co LP	0.02	394.94	14.76	9.48	2.54	421.74
Duluth Steam Plant 1	0.09	218.25	3.69	195.71	1.19	418.92
Minnesota Soybean Processors - Brewster	1.40	16.22	23.44	0.28	285.92	327.27
District Energy St Paul Inc-Hans O Nyman	10.72	210.11	13.90	57.49	19.66	311.89

Facility name	Emissions data (tons)					
	NH_3	NO_X	$PM_{2.5}$	SO_2	VOC	Total
ADM Corn Processing - Marshall	5.19	97.53	41.94	49.12	103.36	297.14
NRG Energy Center Minneapolis	2.77	276.68	9.79	2.39	5.39	297.02
Advanced Disposal Services Rolling Hills Landfill	0.00	4.27	2.85	265.30	2.14	274.56
CHS	0.10	20.31	7.19	0.13	239.92	267.64
Valero Welcome Plant	5.23	78.78	18.87	78.48	61.77	243.13
Xcel Energy - Riverside Generating Plant	73.08	155.86	3.05	5.11	4.37	241.46
Norbord Minnesota	15.45	114.92	74.26	5.45	28.77	238.85
SOUTH ST PAUL	0.09	211.63	5.75	0.10	14.58	232.15
Ag Processing Inc - Dawson	1.09	34.03	29.82	0.20	164.64	229.78
Heartland Corn Products	4.22	91.90	45.36	3.72	67.13	212.33
Marvin Windows & Doors	4.08	18.19	17.03	1.46	168.35	209.10
Guardian Energy LLC	3.15	34.34	30.12	87.20	54.01	208.81
Potlatch Land & Lumber LLC - Bemidji	14.33	45.11	39.88	5.25	101.66	206.24
Cummins Power Generation	0.95	139.38	5.63	16.61	40.07	202.65
Mid Continent Cabinetry	0.04	1.21	12.07	0.01	185.63	198.96
Mayo Medical Center Rochester	0.36	191.39	0.93	0.95	4.52	198.15
Hormel Foods Corporation - Austin Plant	1.21	36.83	147.50	0.24	5.33	191.11
Xcel Energy - High Bridge Generating Plant	66.86	116.33	2.81	4.68	0.41	191.09
NORTHTOWN	0.06	166.43	4.12	0.07	10.39	181.07
MOM Brands	1.10	34.50	73.79	0.21	67.74	177.34
Northstar Ethanol LLC dba Poet Biorefining - Lake Crystal	2.57	74.08	39.62	0.49	54.96	171.72
Bushmills Ethanol	2.34	45.65	27.22	25.47	66.90	167.58
CertainTeed Corp	0.23	7.34	70.97	34.76	53.61	166.92
Burnsville Sanitary Landfill	0.00	105.43	18.92	34.28	6.47	165.10
Green Plains Fairmont LLC	4.34	68.41	31.96	8.85	50.03	163.59
Olmsted Waste-to-Energy Facility	0.96	139.19	6.58	10.64	5.26	162.62
Agra Resources LLC dba POET Biorefining -Glenville	1.95	49.74	49.47	0.37	60.89	162.42
Gerdau Ameristeel US Inc - Saint Paul Mill	0.85	67.98	22.86	4.78	62.22	158.69
Pope/Douglas Solid Waste Management	0.00	139.45	2.17	16.07	0.53	158.22
Chippewa Valley Ethanol Co LLLP	1.16	40.36	10.78	0.42	97.67	150.38

Facility name	Emissions data (tons)					
	NH_3	NO_X	$PM_{2.5}$	SO_2	VOC	Total
3M - Maplewood	2.31	135.06	0.45	1.76	5.06	144.64
Crystal Cabinet Works Inc	0.16	0.89	14.49	0.01	126.66	142.20
Elk River Landfill	0.00	91.47	28.25	3.81	11.41	134.95
Green Plains Otter Tail LLC	2.56	28.37	23.40	12.77	67.79	134.89
Lamb Weston/RDO Frozen	1.06	27.33	69.84	29.55	4.72	132.50
Highwater Ethanol LLC	2.25	56.08	12.20	28.53	33.20	132.26
Northshore Mining Co - Babbitt	0.00	2.09	128.42	0.16	0.16	130.83
Dura Supreme Inc	0.03	0.89	19.84	0.01	109.37	130.14
USG Interiors LLC - Cloquet	1.78	54.82	62.45	0.33	10.09	129.47
Ethanol 2000 LLP dba POET Biorefining Bingham Lake	1.61	33.52	7.83	0.30	85.14	128.40
Knife River Corp N Central Sauk Rapids NM	0.00	71.21	44.53	4.68	5.81	126.23
University of MN - Twin Cities	0.55	112.61	1.83	3.32	6.33	124.63
ME Global Inc	0.15	10.44	41.16	5.58	55.36	112.69
Granite Falls Energy LLC	2.61	45.75	20.66	2.34	41.03	112.38
Al-Corn Clean Fuel	0.01	30.43	23.07	0.65	57.23	111.40
Viracon Inc	0.07	3.56	66.86	0.01	39.81	110.30
Spruce Ridge Resource Management Facility	0.00	69.96	27.99	2.81	7.74	108.50
Liberty Paper Inc	0.00	2.92	0.32	51.30	51.65	106.19
Mayo Clinic Hospital - Rochester	4.14	98.01	0.45	1.25	1.97	105.83
Xcel Energy - Black Dog Generating Plant	20.30	70.15	10.14	2.71	1.75	105.06
St Paul Downtown Holman Fld	0.00	58.91	6.67	5.88	32.45	103.92
Hill Wood Products Inc	0.25	0.79	99.44	0.03	2.48	102.99
POET Biorefining - Preston	1.97	22.52	19.57	0.37	56.17	100.59
3M - Cottage Grove - Corporate Incinerator	0.00	69.10	3.33	0.69	27.44	100.56
Remaining sources and summary information						
214 individual facilities (total emissions < 100 tpy)	170.72	4,240.97	1,919.73	263.95	1,355.05	7,950.42
Grand total	1,077.57	63,326.01	10,825.33	28,498.18	11,308.69	115,035.78

To identify the sources to be selected for analysis, the MPCA evaluated the emission totals from facilities and the associated distance to both Minnesota Class I areas, to determine which sources would conduct a four-factor analysis. In this evaluation, Q represented the sum of the identified pollutant emissions at a facility-wide level (i.e., it included all emitting processes at the facility). The tables below provide a summary of the Q/d Analysis for facilities with a Q/d value greater than or equal to one, with the Q/d values for the remaining sources (i.e., those with a Q/d value less than one) summarized in one row for conciseness. This information is identified to provide the information needed to determine the percentile (percent of the total Q/d for the Class I area) and cumulative percentile for the respective Class I area.

In its August 2019 Guidance, U.S. EPA recommends that states repeat the source selection step from the perspective of each Class I area within the state and each Class I area in another state that may be affected by emissions from within the state.[78] As a result, MPCA performed this analysis for each Minnesota Class I area (Boundary Waters and Voyageurs). Furthermore, the nearest Class I area for all Minnesota sources evaluated was either Boundary Waters or Voyageurs and performing the Q/d analysis using the distance to either Boundary Waters or Voyageurs produces the highest Q/d value. Therefore, performing the Q/d analysis using Class I areas in other states would not have produced any higher Q/d values nor changed the sources selected. Additionally, Minnesota is the major contributor to visibility impairment at its own Class I areas, as discussed in Section 2.2.2, and no states have notified Minnesota that they identified Minnesota emissions as contributing to visibility impairment at their Class I area(s). Given the above considerations, the MPCA did not repeat this Q/d analysis for Class I areas in other states.

Table 29 below displays the facility location, emissions data (total emissions of NO_X, SO_2, $PM_{2.5}$, NH_3, and VOCs), distance, the associated Q/d value, percentile (percent of the total Q/d for the Class I area), and cumulative percentile for the Boundary Waters Class I area.

Table 29. Boundary Waters Q/d analysis information

Facility name	Facility location		Emissions data (tons)	Distance (km)	Q/d	Percentile	Cumulative percentile
	Latitude	Longitude					
US Steel Corp - Minntac	47.5645	-92.6306	9,473.25	95.01	99.71	15.86%	15.86%
Northshore Mining Co - Silver Bay	47.2865	-91.2611	4,051.03	75.56	53.61	8.53%	24.39%
Xcel Energy - Sherburne Generating Plant	45.3792	-93.8958	17,707.30	339.54	52.15	8.30%	32.69%
Minnesota Power Inc - Boswell Energy Ctr	47.2617	-93.6535	9,214.13	179.02	51.47	8.19%	40.88%
Hibbing Taconite Co	47.4768	-92.9673	5,619.76	122.02	46.06	7.33%	48.20%
US Steel Corp - Keetac	47.4133	-93.0636	5,995.44	131.67	45.53	7.24%	55.45%
United Taconite LLC - Fairlane Plant	47.3527	-92.5764	4,469.11	104.60	42.72	6.80%	62.24%
Cleveland Cliffs Minorca Mine Inc	47.5591	-92.5190	3,522.62	87.91	40.07	6.37%	68.62%
Minnesota Power - Taconite Harbor Energy Center	47.5313	-90.9113	1,310.23	63.64	20.59	3.28%	71.89%
Sappi Cloquet LLC	46.7241	-92.4313	1,772.68	153.31	11.56	1.84%	73.73%
Xcel Energy - Allen S King Generating Plant	45.0301	-92.7789	3,208.40	339.23	9.46	1.50%	75.24%
Virginia Department of Public Utilities	47.5223	-92.5409	723.03	91.42	7.91	1.26%	76.50%

[78] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 19.

Facility name	Facility location		Emissions data (tons)	Distance (km)	Q/d	Percentile	Cumulative percentile
	Latitude	Longitude					
Minneapolis-St Paul International Airport	44.8851	-93.2166	2,752.07	365.48	7.53	1.20%	77.69%
Hibbing Public Utilities Commission	47.4295	-92.9350	913.53	122.27	7.47	1.19%	78.88%
Flint Hills Resources Pine Bend Refinery	44.7644	-93.0395	2,773.87	373.56	7.43	1.18%	80.06%
Boise White Paper LLC - Intl Falls	48.6055	-93.4067	1,141.73	159.46	7.16	1.14%	81.20%
American Crystal Sugar - Crookston	47.7644	-96.6331	2,351.92	384.22	6.12	0.97%	82.18%
Blandin Paper Co/MN Power - Rapids Energy Center	47.2338	-93.5366	872.57	172.56	5.06	0.80%	82.98%
American Crystal Sugar - East Grand Forks	47.9271	-97.0064	1,994.83	410.92	4.85	0.77%	83.75%
Southern Minnesota Beet Sugar Coop	44.7975	-95.1720	2,080.62	450.04	4.62	0.74%	84.49%
Minnesota Power - Hibbard Renewable Energy Ctr	46.7355	-92.1528	660.39	143.65	4.60	0.73%	85.22%
Otter Tail Power Co	46.2904	-96.0430	1,352.47	390.63	3.46	0.55%	85.77%
Anchor Glass Container Corp	44.7965	-93.4674	1,235.51	381.95	3.23	0.51%	86.29%
Northshore Mining Co - Babbitt	47.6681	-91.8845	130.83	42.51	3.08	0.49%	86.78%
American Crystal Sugar - Moorhead	46.9007	-96.7605	1,269.65	413.18	3.07	0.49%	87.27%
Duluth Steam Plant 1	46.7861	-92.0956	418.92	136.89	3.06	0.49%	87.75%
Saint Paul Park Refining Co LLC	44.8519	-93.0013	1,029.68	363.37	2.83	0.45%	88.20%
Andersen Corp	45.0253	-92.7795	907.26	339.76	2.67	0.42%	88.63%
Gopher Resource	44.8353	-93.1200	791.23	368.10	2.15	0.34%	88.97%
Xcel Energy - Red Wing Generating Plant	44.5691	-92.5165	766.03	384.10	1.99	0.32%	89.29%
CHS Mankato	44.1572	-94.0309	872.94	465.03	1.88	0.30%	89.59%
3M - Hutchinson Tape Manufacturing Plant	44.8809	-94.3607	682.27	405.92	1.68	0.27%	89.85%
ADM - Mankato	44.1869	-93.9954	666.63	460.86	1.45	0.23%	90.08%
USG Interiors - Red Wing	44.5563	-92.4839	550.70	384.99	1.43	0.23%	90.31%
Xcel Energy - Key City/Wilmarth	44.1971	-94.0085	657.01	460.25	1.43	0.23%	90.54%
CHS Fairmont	43.6684	-94.5063	736.66	530.37	1.39	0.22%	90.76%
Benson Power Biomass Plant	45.2996	-95.5604	586.53	428.15	1.37	0.22%	90.98%
Great River Energy	45.2968	-93.5580	456.66	334.46	1.37	0.22%	91.19%

Facility name	Facility location		Emissions data (tons)	Distance (km)	Q/d	Percentile	Cumulative percentile
	Latitude	Longitude					
WestRock MN Corp	44.9600	-93.1944	458.14	357.06	1.28	0.20%	91.40%
Willmar Municipal Utilities	45.1215	-95.0524	530.00	415.96	1.27	0.20%	91.60%
Covanta Hennepin Energy Resource Co LP	44.9844	-93.2787	421.74	356.95	1.18	0.19%	91.79%
Koda Energy LLC	44.7950	-93.5387	450.24	384.30	1.17	0.19%	91.98%
Hill Wood Products Inc	47.8626	-92.7435	102.99	93.60	1.10	0.18%	92.15%
Remaining sources and summary information							
268 individual facilities (Q/d < 1)	-	-	17,353.16	-	49.34	7.85%	100.00%
Grand total	-	-	115,035.78	-	628.58	100.00%	100.00%

Table 30 below displays the facility location, emissions data (total emissions of NO_X, SO_2, $PM_{2.5}$, NH_3, and VOCs), distance, and the associated Q/d value, percentile (percent of the total Q/d for the Class I area), and cumulative percentile for the Voyageurs Class I area.

Table 30. Voyageurs Q/d Analysis information

Facility name	Facility location		Emissions data (tons)	Distance (km)	Q/d	Percentile	Cumulative percentile
	Latitude	Longitude					
US Steel Corp - Minntac	47.5645	-92.6306	9,473.25	95.56	99.13	16.06%	16.06%
Minnesota Power Inc - Boswell Energy Ctr	47.2617	-93.6535	9,214.13	142.17	64.81	10.50%	26.56%
Hibbing Taconite Co	47.4768	-92.9673	5,619.76	104.68	53.68	8.70%	35.26%
US Steel Corp - Keetac	47.4133	-93.0636	5,995.44	112.62	53.24	8.63%	43.89%
Xcel Energy - Sherburne Generating Plant	45.3792	-93.8958	17,707.30	347.29	50.99	8.26%	52.15%
United Taconite LLC - Fairlane Plant	47.3527	-92.5764	4,469.11	119.48	37.40	6.06%	58.21%
Cleveland Cliffs Minorca Mine Inc	47.5591	-92.5190	3,522.62	97.77	36.03	5.84%	64.05%
Boise White Paper LLC - Intl Falls	48.6055	-93.4067	1,141.73	47.73	23.92	3.88%	67.92%
Northshore Mining Co - Silver Bay	47.2865	-91.2611	4,051.03	171.53	23.62	3.83%	71.75%
Sappi Cloquet LLC	46.7241	-92.4313	1,772.68	190.32	9.31	1.51%	73.26%
Xcel Energy - Allen S King Generating Plant	45.0301	-92.7789	3,208.40	376.56	8.52	1.38%	74.64%
Hibbing Public Utilities Commission	47.4295	-92.9350	913.53	109.73	8.33	1.35%	75.99%
American Crystal Sugar - Crookston	47.7644	-96.6331	2,351.92	291.92	8.06	1.31%	77.29%

Facility name	Facility location		Emissions data (tons)	Distance (km)	Q/d	Percentile	Cumulative percentile
	Latitude	Longitude					
Minnesota Power - Taconite Harbor Energy Center	47.5313	-90.9113	1,310.23	173.32	7.56	1.22%	78.52%
Virginia Department of Public Utilities	47.5223	-92.5409	723.03	101.40	7.13	1.16%	79.67%
Minneapolis-St Paul International Airport	44.8851	-93.2166	2,752.07	393.79	6.99	1.13%	80.80%
Flint Hills Resources Pine Bend Refinery	44.7644	-93.0395	2,773.87	406.43	6.82	1.11%	81.91%
American Crystal Sugar - East Grand Forks	47.9271	-97.0064	1,994.83	314.80	6.34	1.03%	82.94%
Blandin Paper Co/MN Power - Rapids Energy Center	47.2338	-93.5366	872.57	141.49	6.17	1.00%	83.94%
Southern Minnesota Beet Sugar Coop	44.7975	-95.1720	2,080.62	440.48	4.72	0.77%	84.70%
Otter Tail Power Co	46.2904	-96.0430	1,352.47	338.44	4.00	0.65%	85.35%
American Crystal Sugar - Moorhead	46.9007	-96.7605	1,269.65	339.42	3.74	0.61%	85.96%
Minnesota Power - Hibbard Renewable Energy Ctr	46.7355	-92.1528	660.39	193.47	3.41	0.55%	86.51%
Anchor Glass Container Corp	44.7965	-93.4674	1,235.51	405.49	3.05	0.49%	87.00%
Saint Paul Park Refining Co LLC	44.8519	-93.0013	1,029.68	396.60	2.60	0.42%	87.42%
Andersen Corp	45.0253	-92.7795	907.26	377.09	2.41	0.39%	87.81%
Duluth Steam Plant 1	46.7861	-92.0956	418.92	189.24	2.21	0.36%	88.17%
Gopher Resource	44.8353	-93.1200	791.23	398.84	1.98	0.32%	88.49%
CHS Mankato	44.1572	-94.0309	872.94	482.64	1.81	0.29%	88.79%
Xcel Energy - Red Wing Generating Plant	44.5691	-92.5165	766.03	428.52	1.79	0.29%	89.08%
Hill Wood Products Inc	47.8626	-92.7435	102.99	61.55	1.67	0.27%	89.35%
3M - Hutchinson Tape Manufacturing Plant	44.8809	-94.3607	682.27	410.19	1.66	0.27%	89.62%
Benson Power Biomass Plant	45.2996	-95.5604	586.53	404.08	1.45	0.24%	89.85%
ADM - Mankato	44.1869	-93.9954	666.63	478.87	1.39	0.23%	90.08%
Xcel Energy - Key City/Wilmarth	44.1971	-94.0085	657.01	477.94	1.37	0.22%	90.30%
CHS Fairmont	43.6684	-94.5063	736.66	543.76	1.35	0.22%	90.52%
Willmar Municipal Utilities	45.1215	-95.0524	530.00	403.66	1.31	0.21%	90.73%
Great River Energy	45.2968	-93.5580	456.66	351.27	1.30	0.21%	90.94%

Facility name	Facility location		Emissions data (tons)	Distance (km)	Q/d	Percentile	Cumulative percentile
	Latitude	Longitude					
USG Interiors - Red Wing	44.5563	-92.4839	550.70	430.09	1.28	0.21%	91.15%
Norbord Minnesota	47.5111	-95.0825	238.85	195.69	1.22	0.20%	91.35%
Northshore Mining Co - Babbitt	47.6681	-91.8845	130.83	108.66	1.20	0.20%	91.54%
WestRock MN Corp	44.9600	-93.1944	458.14	385.35	1.19	0.19%	91.74%
Potlatch Land & Lumber LLC - Bemidji	47.3881	-94.7560	206.24	183.56	1.12	0.18%	91.92%
Koda Energy LLC	44.7950	-93.5387	450.24	406.35	1.11	0.18%	92.10%
Specialty Minerals Inc	48.6037	-93.4051	52.60	47.54	1.11	0.18%	92.28%
Covanta Hennepin Energy Resource Co LP	44.9844	-93.2787	421.74	383.17	1.10	0.18%	92.45%
Marvin Windows & Doors	48.9145	-95.3230	209.10	191.71	1.09	0.18%	92.63%
International Bildrite Inc	48.6016	-93.4000	49.93	47.10	1.06	0.17%	92.80%
Remaining sources and summary information							
263 individual facilities (Q/d < 1)	-	-	16,596.43	-	44.42	7.20%	100.00%
Grand total	-	-	115,035.78	-	617.18	100.00%	100.00%

2.3.3. Option to consider the four statutory factors when selecting sources

U.S. EPA offers recommendations in its August 2019 Guidance on additional information, such as the four statutory factors, that a state may consider in the source selection step. The guidance continues that in particular circumstances, the information may indicate that it is reasonable to exclude a source from the control measure analysis because it is clear that no additional control measures would be implemented as a result.[79]

One of the four factors that the MPCA specifically evaluated during the source selection process was the remaining useful life of the source. U.S. EPA identified that it may be reasonable for a state to not select a source with an expected shutdown/retirement prior to December 31, 2028, where there is an enforceable requirement to do so.[80] This reasoning is based on the time needed for U.S. EPA to review and act on a state's SIP, the time required for the source to implement any emission reduction measures, and the limited visibility benefit realized of those measures prior to the shutdown date. U.S. EPA also clarifies that the year 2028 is not a bright line for this consideration, so a state may also be able to justify not selecting a source for analysis if there is an enforceable requirement for that source to shut down by a date after 2028.[81]

Of the sources that MPCA requested prepare four-factor analyses (see Table 27), several provided additional information in response to the request, or in later discussions with MPCA, regarding the

[79] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 20.
[80] *See id.*
[81] *See id.*

remaining useful life of specific emission units at their sources. The additional information provided by these sources is available in Appendix B. Four-Factor Analyses - Facility Responses.

Where the retirement dates were not already incorporated into the source's Title V operating permit, the MPCA established enforceable requirements, via an administrative order, for the proposed retirement dates. Table 31 below identifies the emission units that were excluded from the control measure analysis, the associated retirement dates, and the mechanism that establishes those retirement dates as enforceable. Each of these emission unit retirements were accounted for in estimating the projected 2028 emissions included in the MPCA's modeling analysis (see Section 2.6 for additional details regarding the modeling analysis).

Table 31. Summary of emission unit retirements

Facility name	Emission unit	Retirement date	Enforceable mechanism
Minnesota Power - Boswell Energy Center	Unit 1	Permanently retired in December 2018	Title V operating permit (see Air Emissions Permit No. 06100004-008, conditions 5.18.16 and 5.19.16).
	Unit 2		
Minnesota Power - Taconite Harbor Energy	Boiler 1	Proposed retirement by March 2023	See Appendix D. MPCA Administrative Orders
	Boiler 2		
Northshore Mining - Silver Bay	Power Boiler 1	Proposed idling through 2031	See Appendix D. MPCA Administrative Orders
	Power Boiler 2		
Virginia Department of Public Utilities	Boiler 7	Proposed retirement by January 2025	See Appendix D. MPCA Administrative Orders
	Boiler 9	Permanently retired in March 2021	Title V operating permit (see Air Emissions Permit No. 13700028-102, condition 5.3.1).
Xcel Energy - Allen S. King	Boiler 1	Proposed retirement by December 2028	See Appendix D. MPCA Administrative Orders
Xcel Energy - Sherburne	Unit 1	Permanent retirement by December 2026	Title V operating permit (see Air Emissions Permit No. 14100004-101, conditions 5.57.1 and 5.58.1).
	Unit 2	Permanent retirement by December 2023	
	Unit 3	Proposed retirement by December 2030	See Appendix D. MPCA Administrative Orders

While the MPCA originally requested that these sources prepare and submit an analysis of control measures for the identified emission units, they were ultimately removed from further analysis due to the proposed retirement dates identified and required by enforceable mechanisms already in place or established through administrative orders. Subsequently, the MPCA concludes that no additional control measures would be reasonable to require in this implementation period given the remaining useful life of the identified emission units ending prior to, or shortly after, the conclusion of the second regional haze implementation period in 2028.

Additional information specifically regarding Northshore Mining - Silver Bay (Power Boiler 1 and 2) and Virginia Department of Public Utilities (Boiler 7) is provided in Section 2.4 and Section 2.5 as these sources also provided control information as part of the four-factor analyses requested for these emission units.

2.3.4. Option to consider the five required additional factors when selecting sources

The Regional Haze Rule requires states to consider five additional factors in developing its long-term strategy. The five additional factors are identified in 40 CFR § 51.308(f)(2)(iv).

The State must consider the following additional 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) Source retirement and replacement schedules;*
- *(D) Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and*
- *(E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.*

However, the Regional Haze Rule does not specify when these factors must be considered in developing a state's long-term strategy. U.S. EPA clarifies in its August 2019 Guidance that states can consider these factors during the source selection step or in the subsequent analysis of control measures.[82] The following sections document the MPCA's consideration of the five factors identified in 40 CFR § 51.308(f)(2)(iv).

Emission reductions due to ongoing air pollution control programs. 40 CFR § 51.308(f)(2)(iv)(A) requires Minnesota to consider emission reductions due to ongoing air pollution control programs; including measures to address reasonably attributable visibility impairment. U.S. EPA clarifies in its August 2019 Guidance that this factor is inherently considered in the process of source selection if visibility impacts are used to select sources, since those impacts depend on emission reductions from ongoing control programs.[83]

Regarding measures to address reasonably attributable visibility impairment (RAVI), Minnesota has one source, Xcel Energy - Sherburne Generating Plant, that was previously certified as a source of RAVI in the first regional haze implementation period. On March 7, 2016, U.S. EPA promulgated a FIP for visibility to establish emission limits with an effective date of April 6, 2016.[84] These emission limits and associated compliance provisions are identified in the Minnesota RAVI FIP under 40 CFR § 52.1236. Additional information regarding RAVI is included in Section 2.8.2.

Emission reduction measures resulting from control programs were inherently considered as U.S. EPA identifies in its guidance, as the MPCA selected sources for analysis based on the surrogate visibility metric, via the Q/d Analysis described in Section 2.3.2 above.[85] Reduction measures, such as those from federal standards and other "on-the-books" controls, were included in the emission inventories used in U.S. EPA's modeling platforms (2011 and 2016) that LADCO and Minnesota used as a starting point for the Q/d Analysis and the regional haze modeling analyses performed by LADCO and the MPCA. U.S. EPA's modeling platforms included emissions projections to 2028 that accounted for the expected effects of rules and regulations such as New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and other federal/state regulations. The MPCA made a specific modification in its modeling analysis to account for the Regional Haze Taconite FIP, discussed previously in Section 1.3, and the estimated emission reductions due to that program as detailed in Section 2.6.1.

In its August 2019 Guidance, U.S. EPA also states that the factor specified in 40 CFR § 51.308(f)(2)(iv)(A) is considered when states do not select sources for an analysis of control measures based on those

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[82] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 21.
[83] *See id.*
[84] *See* Air Plan Approval; Minnesota; Revision to Visibility Federal Implementation Plan, 81 Fed. Reg. 11668 (Mar. 7, 2016).
[85] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 21.

sources already having effective emissions controls in place.[86] The expected emission changes due to the Regional Haze Taconite FIP are discussed in more detail in Section 2.3.5 below alongside other sources not selected for analysis due to already having effective emissions controls in place. These emission reductions are reflected in the 2028 modeling inventory.

Additionally, Minnesota has also addressed non-point sources of emissions through a variety of programs discussed in more detail in Section 3.1. Non-point pollution reductions. While these programs and associated emission reductions are not reflected in the 2028 modeling inventory, they may also result in visibility improvement in the Boundary Waters and Voyageurs Class I areas.

Measures to mitigate the impacts of construction activities. 40 CFR § 51.308(f)(2)(iv)(B) requires Minnesota to consider measures to mitigate the impacts of construction activities. Some of the main impacts of construction activities include the impacts of emissions from nonroad mobile and diesel engines and fugitive emissions resulting from land clearing and construction. Emissions from nonroad mobile sources and diesel engines are generally regulated by U.S. EPA by emission standards that engine manufacturers must demonstrate compliance through emissions testing to certify their engines to those standards.

Vehicle and engine emission standards, as well as supporting requirements, developed by U.S. EPA are specified in 40 CFR Parts 1027 through 1090. Furthermore, states and local units of government are generally prohibited from adopting their own emission standards, as specified in 40 CFR § 1074.10, for certain nonroad vehicles or engines.

In addition, Minnesota has a state rule, Minnesota Rule 7011.0150 (Minn. R. 7011.0150), which requires all reasonable measures to be undertaken to prevent particulate matter from becoming airborne. This rule is already included in Minnesota's SIP.

7011.0150 PREVENTING PARTICULATE MATTER FROM BECOMING AIRBORNE.

A. *No person shall cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne.*

B. *No person shall cause or permit a building or its appurtenances or a road, or a driveway, or an open area to be constructed, used, repaired, or demolished without applying all such reasonable measures as may be required to prevent particulate matter from becoming airborne. All persons shall take reasonable precautions to prevent the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate. The commissioner may require such reasonable measures as may be necessary to prevent particulate matter from becoming airborne including, but not limited to, paving or frequent clearing of roads, driveways, and parking lots; application of dust-free surfaces; application of water; and the planting and maintenance of vegetative ground cover.*[87]

As discussed previously in Section 2.1, data from the IMPROVE monitoring sites at the Boundary Waters and Voyageurs Class I areas indicates that particulate matter, such as dust from construction activities, is not a large contributor to visibility impairment in these areas. As a result, the MPCA did not select construction activities as a source category for analysis of control measures given the monitoring data that indicates a small impact from all coarse particulate matter and that Minnesota does not have the authority to establish additional emission standards for nonroad vehicles and engines. The impact of

[86] *See id.*
[87] Minn. R. 7011.0150 (2022).

construction activities will continue to be mitigated through the federal general conformity and transportation conformity rules, which are included in Minnesota's SIP.

Source retirement and replacement schedules. 40 CFR § 51.308(f)(2)(iv)(C) requires Minnesota to consider source retirement and replacement schedules in developing its long-term strategy. This factor was considered by not selecting sources for control measure analysis as discussed in Section 2.3.3 and Table 31. Summary of emission unit retirements.

Basic smoke management practices. 40 CFR § 51.308(f)(2)(iv)(D) requires Minnesota to consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs. Prescribed fire and managed wildfire have been used in Minnesota for many years to improve and maintain natural resources. The Minnesota Smoke Management Plan was created and implemented for three reasons:

- To improve visibility in the Class I areas in Minnesota as part of the Regional Haze Rules.
- The use of prescribed fire as a management tool was expected to continue.
- The adoption of a smoke management program may prevent violations of the particulate matter and ozone National Ambient Air Quality Standards (NAAQS) due to emissions from managed wildland fires in Minnesota.[88]

The Minnesota Smoke Management Plan is based on Section VI, Smoke Management Programs, of the U.S. EPA's *Interim Air Quality Policy on Wildland and Prescribed Fires (April 23, 1998)*.[89] The planning process for Minnesota's document began early in 1999 with the formation of a subcommittee of the Minnesota Incident Command System (MNICS) Prescribed Fire Working Team. Participants included representatives from the Minnesota Pollution Control Agency (MPCA), National Weather Service (NWS), Minnesota Department of Natural Resources (MNDNR), U.S. National Park Service (U.S. NPS), U.S. Fish & Wildlife Service (U.S. FWS), U.S. Forest Service (U.S. FS), Minnesota Department of Military Affairs (MNDMA), and the Bureau of Indian Affairs (BIA). A Memorandum of Agreement for the Minnesota Smoke Management Plan was signed and accepted in 2007 and again with formal revisions in 2014, 2016, and the latest revision in April 2021.[90]

Agricultural burning requires an open burning permit from the MNDNR. In general, agricultural burning in Minnesota is limited to grass and stubble burning, particularly of bluegrass and timothy grass. This light fuel type produces short-term smoke events without a lot of combustion of biomass and smoldering. In addition, most agricultural burning occurs in the northwest area of the state, away from the Class I areas. Agricultural burning is not covered by Minnesota's Smoke Management Plan, and U.S. EPA's *Interim Air Quality Policy on Wildland and Prescribed Fires* specifies that it does not apply to agricultural burning.

As discussed previously in Section 2.3.1, data from the IMPROVE monitoring sites at the Boundary Waters and Voyageurs Class I areas indicates that elemental and organic carbon, pollutants typically formed from fire, are not large contributors to visibility impairment in these areas. As result, Minnesota is not addressing prescribed fire use in this SIP beyond the revision to the Minnesota Smoke Management Plan in April 2021.

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[88] *See* Minnesota Prescribed Fire/Fuels Working Team, Minnesota Smoke Management Plan 2 (Apr. 5, 2021).
[89] *See* U.S. EPA, Interim Air Quality Policy on Wildland and Prescribed Fires (Apr. 23, 1998), https://archive.epa.gov/ttn/pm/web/pdf/firefnl.pdf.
[90] *See* Minnesota Prescribed Fire/Fuels Working Team, Minnesota Smoke Management Plan 2 (Apr. 5, 2021).

Anticipated net effect on visibility due to projected emission changes in this implementation period. Both of Minnesota's Class I areas have seen improvements in visibility conditions over the first implementation period. Minnesota achieved the reasonable progress goals for both Boundary Waters and Voyageurs as discussed earlier in Section 2.1. Measured progress towards meeting the 2018 reasonable progress goal at the Boundary Waters and Voyageurs Class I areas is shown in Figure 4.

U.S. EPA suggests in its August 2019 Guidance that the amount of visibility progress in the second implementation period that is anticipated from projected emission changes from in-state sources may be a useful consideration in determining which sources to select for a control measure analysis. However, U.S. EPA clarifies that visibility conditions being on or below the Uniform Rate of Progress (URP) glidepath is not a sufficient basis by itself to select no sources for an analysis of control measures.[91]

While visibility projections are below the URP glidepath for both the Boundary Waters and Voyageurs, the U.S. EPA has reiterated that this is not a "safe harbor" in multiple instances.[92] The U.S. EPA has stated that treating the URP as a safe harbor would be "inconsistent with the statutory requirement that states assess the potential to make further reasonable progress towards natural visibility goal in every implementation period."[93] Visibility projections being below the URP glidepath serve as a demonstration, after a state has gone through the source selection and control measure process, that it has no "robust demonstration" obligation per 40 CFR § 51.308(f)(3)(ii).

U.S. EPA also provided additional information in its July 2021 Clarification Memo regarding the use of visibility benefits alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress. The memo reiterates that other reasonable factors may be considered in reasonable progress determinations, so long as those factors are considered in a reasonable way that does not undermine or nullify the four statutory factors.[94]

The MPCA did not consider the anticipated net effect on visibility due to emission changes expected in this implementation period, instead relying on the information documented in Section 2.3 to select sources for an analysis of control measures. As a result, the MPCA believes it made a reasonable selection of sources for an analysis of control measures in this implementation period. The result of the source selection process is identified in Section 2.3.6 below.

2.3.5. Sources that have existing effective emission control technology

U.S. EPA states in its August 2019 Guidance that it may be reasonable for states to not select a source for an analysis of control measures when that source already has effective controls in place as a result of a previous Regional Haze SIP or other regulatory requirements.[95] This reasoning is based on if the source is already effectively controlled, it is unlikely that the four-factor analysis would demonstrate that further cost-effective reductions are available. Overall, U.S. EPA highlights where the considerations for certain scenarios are similar to, if not more stringent than, the four statutory factors for reasonable progress and should be consistent with up-to-date, effective, and reasonable control measures.[96] U.S.

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[91] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22.
[92] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 2, 12, 13, 15; Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).
[93] *See* Protection of Visibility: Amendments to Requirements for State Plans 82 Fed. Reg. 3078, at 3093, 3099 (Jan. 10, 2017).
[94] *See* U.S. EPA, July 2021 EPA Clarifications, *supra,* at 13 (quoting U.S. EPA, Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans, EPA-HQ-OAR-2015-0531, at 156 (Dec. 2016)).
[95] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22.
[96] *See id.* at 23.

EPA provides a few examples (in a non-exhaustive fashion) where it may be reasonable for a state not to select an effectively controlled source for further analysis, such as those that have been summarized below:

- Emission units subject to, and complying with, federal standards that regulate emissions of visibility-impairing pollutants such as New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) that were promulgated or reviewed since July 31, 2013.
- Emission units that went through a Best Available Control Technology (BACT) review under the Prevention of Significant Deterioration (PSD) program and received a construction permit since July 31, 2013.
- Emission units that installed and began operating Best Available Retrofit Technology (BART) to meet BART emission limits for the first regional haze implementation period.
- Multiple examples for fuel combustion emission units that are restricted to only combust certain fuels, combust fuels meeting certain sulfur content limits, or already installed certain NO_X/SO_2 control technologies.

U.S. EPA also notes that a state that does not select a source for any of the above examples, or similar reasons, should explain why the decision is consistent with the requirement to make reasonable progress and why it is reasonable to assume that a four-factor analysis would result in the conclusion that no further controls are necessary.[97]

Of the sources that MPCA requested prepare four-factor analyses (see Table 27) several provided additional information in response to the request, or in later discussions with MPCA, regarding the effectiveness of the existing controls on specific emission units at their sources. The additional information provided by these sources is available in Appendix B. Four-Factor Analyses - Facility Responses.

No additional actions were needed to make these control measures enforceable as the measures have been previously incorporated into the source's Title V operating permit or are required through a different mechanism. Table 32 below identifies the emission units that were excluded from the control measure analysis, a summary of what controls or measures in place support an effectively controlled determination, and the mechanism that establishes those controls as enforceable.

Table 32. Summary of emission units with existing effective controls

Facility Name	Emission Unit	Pollutants	Effective Control Measure	Enforceable Mechanism
Boise White Paper	Recovery Furnace	NO_X	Existing BACT emissions limit (NO_X) is comparable to recent BACT determinations for similar combustion units.	See Air Emissions Permit No. 07100002-101, condition 5.11.7.
	Boiler 2	NO_X, SO_2	Existing BACT emissions limit (NO_X and SO_2) is comparable to recent BACT determinations for similar combustion units.	See Air Emissions Permit No. 07100002-101, conditions 5.15.5 - 5.15.7.
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 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.

[97] *See id.* at 22-25.

Facility Name	Emission Unit	Pollutants	Effective Control Measure	Enforceable Mechanism
Hibbing Taconite Company	Indurating Furnace Line 1	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 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.
	Indurating Furnace Line 2	NO_X, SO_2		
	Indurating Furnace Line 3	NO_X, SO_2		
Minnesota Power - Boswell Energy Center	Unit 3	NO_X, SO_2	BART emission limits (NO_X) established in the first regional haze implementation period. Emission limits (SO_2) established by the Mercury Air Toxics Standards (MATS) rule for power plants.	See Air Emissions Permit No. 06100004-102, conditions 5.32.10 and 5.3.14.
	Unit 4	NO_X, SO_2	Existing emission limit (NO_X) is comparable to recent BACT determinations for similar combustion units. Emission limits (SO_2) established by the Mercury Air Toxics Standards (MATS) rule for power plants.	See Air Emissions Permit No. 06100004-102, conditions 5.20.11 and 5.3.14.
Northshore Mining - Silver Bay	Furnace 11	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 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.
	Furnace 12	NO_X, SO_2		
Sappi Cloquet	Recovery Boiler #10	NO_X	BACT emission limits (NO_X) established in Air Emissions Permit No. 01700002-101 issued on June 30, 2017.	See Air Emissions Permit No. 01700002-104, condition 5.17.11.
United Taconite LLC - Fairlane Plant	Line 1 Pellet Induration	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 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.
	Line 2 Pellet Induration	NO_X, SO_2		
US Steel Corporation - Keetac	Grate Kiln	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 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 Corporation - Minntac	Line 3 Rotary Kiln	NO_X, SO_2	BART emission limits (NO_X and SO_2) established by U.S. EPA in the 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.
	Line 4 Rotary Kiln	NO_X, SO_2		
	Line 5 Rotary Kiln	NO_X, SO_2		
	Line 6 Rotary Kiln	NO_X, SO_2		
	Line 7 Rotary Kiln	NO_X, SO_2		

In addition to the existence of an enforceable emission limit or other enforceable requirements, U.S. EPA provided recommendations in its July 2021 Clarification Memo on the specific data and information used to demonstrate that a source's existing measures qualify as "effective controls."[98]

While the MPCA originally requested that these sources prepare and submit an analysis of control measures for the identified emission units, they were ultimately removed from further analysis due to the effectively controlled determination. Subsequently, the MPCA concludes that no additional control measures would be reasonable to require in this implementation period given the existing effective controls of the identified emission units. Additional information specific to each facility and emission unit is provided below.

Boise White Paper. Boise White Paper's Recovery Furnace is a combustion unit that burns black liquor solids (BLS) from the Kraft pulping process to recover spent cooking chemicals. This emission unit is also authorized to burn natural gas, low volume high concentration (LVHC) non-condensable gas (NCG), and BLS blended with distillate oil (#1 or #2). The combustion process generates heat which is recovered by steam generation. The combustion process results in emissions of NO_X and other pollutants.

This emission unit is subject to two NO_X emissions limits (80 ppm by volume (dry) NO_X, corrected to 8% oxygen, as a 30-day rolling average and 110 lb NO_X/hr). These emissions limits were originally established in the 1989 permit for this facility as BACT limits expressed in parts per million (80 ppm by volume (dry) NO_X, corrected to 8% oxygen, as a 30-day rolling average and 86.9 lb NO_X/hr). The hourly NO_X limit was increased over a series of permit amendments that increased the amount of BLS processed at the source. The current 110 lb NO_X/hr limit was established in the October 2008 permit for this facility. However, this emission unit has not undergone a NO_X BACT review since July 31, 2013. Boise White Paper conducted a search of U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC), available in Appendix B. Four-Factor Analyses - Facility Responses, and provided the results showing that the NO_X emissions limits were more stringent than the recent evaluations for similar sources.

These circumstances are similar to examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., an emission unit that went through a BACT review).[99] Regarding NO_X emissions, while the emission unit did not go through BACT since July 31, 2013, the NO_X emissions limits are more stringent than other NO_X evaluations for similar sources as identified in the facility's RBLC search. Given the level of control required for this emission unit, the MPCA determined that it was unlikely that there are further available reasonable controls for this emission unit and removed it from further analysis for this implementation period.

Boise White Paper's Boiler 2 is an industrial boiler that was originally commissioned as a coal-fired boiler. This emission unit is a stoker grate design which produces steam to generate electricity and provide heat for other processes at the plant. The boiler burns primarily hog fuel (biomass which is primarily bark and wood refuse from the facility de-barking process) and is also permitted to burn wastewater treatment plant sludge, paper, and natural gas. The boiler is also a backup combustion source for NCG. The boiler is not authorized to burn coal and the amount of NCG burned in the boiler is limited by the facility's Title V operating permit. Particulate matter emissions from the power boiler are controlled by multiclones and a high-efficiency electrostatic precipitator (ESP). Boiler #2 does not have add-on NO_X controls but does use staged and overfire air to manage the generation of NO_X. The boiler

[98] *See* July 2021 EPA Clarifications*, supra, at 5 and 8-10.*
[99] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.

does not have add-on SO_2 controls but burns low sulfur fuels, and the wood ash provides some dry scrubbing of SO_2 when NCGs are burned concurrently.

This emission unit is subject to a NO_X emissions limit (100.2 lb NO_X/hr as a 30-day rolling average, which is equivalent to 0.25 lb NO_X/MMBtu at the maximum firing rate). This emission limit was originally established in the 1989 permit for this facility as a BACT limit and remained unchanged in a PSD modification of the boiler to include an overfire air system to allow the source to burn more sludge and wood on an hourly basis while remaining in compliance with the applicable NO_X emission limit. However, this emission unit has not undergone a NO_X BACT review since July 31, 2013. Boise White Paper conducted a search of U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) and provided the results showing that the NO_X emissions limit was more stringent than the recent evaluations for similar sources.

This emission unit is also subject to a SO_2 emission limit (9.4 lb SO_2/hr as 12-hour rolling average, which is equivalent to 0.024 lb SO_2/MMBtu at the maximum firing rate). This emission limit was originally established in the 1989 permit for this facility as a BACT limit. However, this emission unit has not undergone an SO_2 BACT review since July 31, 2013. Boise White Paper conducted a search of U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) and provided the results showing that the SO_2 emission limit was more stringent than the recent evaluations for similar sources. Furthermore, the authorized fuels are low-sulfur fuels (with exception for NCG), the majority of the SO_2 emissions from the boiler are a result of NCG combustion, and this emission unit is the secondary NCG combustion source only utilized when the primary combustion source (a lime kiln at the facility) is unavailable. The ability to combust NCG in this boiler is part of the facility's overall strategy for limiting HAP emissions for 40 CFR Part 63 Subpart S (NESHAP for the Pulp/Paper Industry) and serves as an engineered control to maintain the continued safe operation of the Kraft pulping equipment and process.

These circumstances are similar to examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., an emission unit that went through a BACT review).[100] Regarding NO_X and SO_2 emissions, while the emission unit did not go through BACT since July 31, 2013, the NO_X and SO_2 emissions limits are more stringent than other NO_X and SO_2 evaluations for similar sources. Given the level of control required for this emission unit, the MPCA determined that it was unlikely that there are further available reasonable controls for this emission unit and removed it from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

[100] *See id.*

Table 33. Boise White Paper, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Recovery Furnace						
Heat Input (MMBtu)	6,134,104	6,258,033	6,515,796	6,595,223	6,427,124	-
NO_X emissions (tons)	321.70	366.30	382.50	336.90	358.40	322.58
NO_X emission rate (lb/MMBtu)	0.10	0.12	0.12	0.10	0.11	-
Boiler 2						
Heat Input (MMBtu)	2,467,373	2,266,219	2,392,603	2,236,154	2,195,910	-
NO_X emissions (tons)	365.50	368.10	359.00	332.20	360.10	400.54
NO_X emission rate (lb/MMBtu)	0.30	0.32	0.30	0.30	0.33	-
SO_2 emissions (tons)	29.01	34.68	26.95	21.41	8.95	31.59
SO_2 emission rate (lb/MMBtu)	0.02	0.03	0.02	0.02	0.01	-

While the projected emissions for 2028 are lower than reported emissions for some years displayed, the facility has been implementing the existing controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above. MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

Cleveland Cliffs Minorca Mine. The indurating furnace at Cleveland Cliffs Minorca Mine was a BART-eligible emission unit, and BART emission limits on NO_X and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first regional haze implementation period. The emission unit is only capable of burning natural gas and fuel oil. Since these fuels are low in sulfur, the primary source of sulfur in these furnaces is the iron ore used to form the taconite pellets. Additional sulfur may be present in the additives used in the taconite pellets. This emission unit utilizes existing wet scrubbers for SO_2 control.

This emission unit is subject to a NO_X emissions limit (1.2-1.8 lb NO_X/MMBtu as a 30-day rolling average) established in the Taconite FIP dated April 12, 2016. This emission unit required add-on controls (low NO_X burners) to meet the NO_X limits. This emission unit is also subject to an SO_2 emissions limit (38.16 lb SO_2/hr as a 30-day rolling average) established in the Taconite FIP dated February 6, 2013. In the 2013 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[101] Regarding NO_X emissions, the emission units installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission units were determined to be BART, meaning no add-on controls were required, the emission units primarily burn natural gas that is inherently low in sulfur and the emission unit is subject to an hourly SO_2 emission rate limit established in the Taconite FIP. Given the level of control required

[101] *See id.*

for these emission units, the MPCA determined that it was unlikely that there are further available reasonable controls for these emission units and removed them from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu or lb/ton pellet) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu or ton pellet) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 34. Cleveland Cliffs - Minorca Mine, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Indurating Machine						
Heat Input (MMBtu)	1,579,589	1,522,441	1,600,764	1,527,874	1,690,674	-
Pellet Production (tons)	3,063,733	3,081,714	3,102,827	3,006,892	3,210,389	-
NO_X emissions (tons)	3,234.60	3,063.00	3,115.70	2,463.90	1,151.10	3,243.47
NO_X emission rate (lb/MMBtu)	4.10	4.02	3.89	3.23	1.36	-
NO_X emission rate (lb/ton pellet)	2.11	1.99	2.01	1.64	0.72	-
SO_2 emissions (tons)	96.95	136.11	180.10	188.18	169.25	97.22
SO_2 emission rate (lb/MMBtu)	0.12	0.18	0.23	0.25	0.20	-
SO_2 emission rate (lb/ton pellet)	0.06	0.09	0.12	0.13	0.11	-

While the projected NO_X emissions for 2028 are higher than reported emissions for some years displayed, the facility has been working to implement the controls described earlier resulting in a decreasing NO_X emission rate over the most recent five years displayed above. Additionally, the most recent years of NO_X emissions data highlights the expected NO_X emission reductions due to the Regional Haze Taconite FIP. Additional detail regarding how MPCA estimated the expected reductions due to the Regional Haze Taconite FIP is available in Section 2.6.1. While the projected SO_2 emissions for 2028 are lower than reported emissions for some years displayed, the facility has been implementing the controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above.

Note that CEMS data for SO_2 emissions was available beginning in 2017 and has been used to calculate annual emissions instead of the previous emission factor determined through emissions testing. MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

Hibbing Taconite Company. Lines 1, 2, and 3 at Hibbing Taconite were BART-eligible emission units and BART emission limits on NO_X and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first regional haze implementation period. Lines 1, 2, and 3 can only burn natural gas and fuel oil. Since these fuels are low in sulfur, the primary source of sulfur in these furnaces is the iron ore used to form the taconite pellets. Additional sulfur may be present in the additives used in the taconite pellets. These emission units utilize existing wet scrubbers for SO_2 control.

These emission units are subject to a NO_X emissions limit (1.2-1.8 lb NO_X/MMBtu for each line as a 30-day rolling average) established in the Taconite FIP dated April 12, 2016. These emission units required add-on controls (low NO_X burners) to meet the NO_X limits. These emission units are also subject to an SO_2 emissions limit (247.8 lb SO_2/hr, averaged across all lines as a 30-day rolling average) established in the Taconite FIP dated February 6, 2013. In the 2013 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[102] Regarding NO_X emissions, the emission units installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission units were determined to be BART, meaning no add-on controls were required, the emission units primarily burn natural gas that is inherently low in sulfur and all emission units are subject to an hourly SO_2 emission rate limit established in the Taconite FIP. Given the level of control required for these emission units, the MPCA determined that it was unlikely that there are further available reasonable controls for these emission units and removed them from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu or lb/ton pellet) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu or ton pellet) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 35. Hibbing Taconite Company, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Indurating Furnace Line 1						
Heat Input (MMBtu)	772,043	759,630	774,560	835,281	593,557	-
Pellet Production (tons)	3,051,086	2,713,483	2,702,362	2,738,857	1,824,134	-
NO_X emissions (tons)	1,197.00	1,649.00	937.00	646.20	436.80	1,200.28

[102] *See id.*

Parameter	2016	2017	2018	2019	2020	2028 Model
NO_X emission rate (lb/MMBtu)	3.10	4.34	2.42	1.55	1.47	-
NO_X emission rate (lb/ton pellet)	0.78	1.22	0.69	0.47	0.48	-
SO_2 emissions (tons)	214.60	261.10	264.80	229.60	157.10	215.19
SO_2 emission rate (lb/MMBtu)	0.56	0.69	0.68	0.55	0.53	-
SO_2 emission rate (lb/ton pellet)	0.14	0.19	0.20	0.17	0.17	-
Indurating Furnace Line 2						
Heat Input (MMBtu)	739,360	671,660	657,036	744,653	653,986	-
Pellet Production (tons)	2,768,051	2,826,608	2,865,126	2,544,562	2,029,781	-
NO_X emissions (tons)	1,762.00	1,094.00	1,041.00	900.50	426.10	1,766.83
NO_X emission rate (lb/MMBtu)	4.77	3.26	3.17	2.42	1.30	-
NO_X emission rate (lb/ton pellet)	1.27	0.77	0.73	0.71	0.42	-
SO_2 emissions (tons)	229.40	288.00	300.60	260.90	197.80	230.03
SO_2 emission rate (lb/MMBtu)	0.62	0.86	0.92	0.70	0.60	-
SO_2 emission rate (lb/ton pellet)	0.17	0.20	0.21	0.21	0.19	-
Indurating Furnace Line 3						
Heat Input (MMBtu)	772,148	748,409	709,931	714,080	684,968	-
Pellet Production (tons)	3,090,384	2,837,688	2,838,400	2,784,305	2,059,719	-
NO_X emissions (tons)	1,354.00	1,238.00	1,228.00	1,260.00	710.90	1,357.71
NO_X emission rate (lb/MMBtu)	3.51	3.31	3.46	3.53	2.08	-
NO_X emission rate (lb/ton pellet)	0.88	0.87	0.87	0.91	0.69	-
SO_2 emissions (tons)	293.00	275.20	272.60	236.20	178.50	293.80
SO_2 emission rate (lb/MMBtu)	0.76	0.74	0.77	0.66	0.52	-
SO_2 emission rate (lb/ton pellet)	0.19	0.19	0.19	0.17	0.17	-

While the projected NO_X emissions for 2028 are higher than reported emissions for some years displayed, the facility has been working to implement the controls described earlier resulting in a decreasing NO_X emission rate over the most recent five years displayed above. Additionally, the most recent years of NO_X emissions data highlights the expected NO_X emission reductions due to the Regional Haze Taconite FIP. Additional detail regarding how MPCA estimated the expected reductions due to the Regional Haze Taconite FIP is available in Section 2.6.1. While the projected SO_2 emissions for 2028 are lower than reported emissions for some years displayed, the facility has been implementing the controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above.

MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

Minnesota Power - Boswell Energy Center. Minnesota Power - Boswell Unit 3 is equipped with low-NO_X burners, overfire air controls, and selective catalytic reduction (SCR) for NO_X control, a wet flue gas desulfurization (FGD) system for SO_2 and acid gas control, and a fabric filter with activated carbon injection for $PM/PM_{10}/PM_{2.5}$ and mercury control.

The NO_X controls were originally installed to control NO_X emissions to meet the BART emissions limit (0.07 lb NO_X/MMBtu as a 30-day rolling average) established for this emission unit in the MPCA's 2009 Regional Haze SIP, among other justifications as well. MPCA ultimately replaced source-specific BART determinations for electricity generating units (EGUs) proposed in the 2009 Regional Haze SIP with participation in the Cross State Air Pollution Rule (CSAPR) that when U.S. EPA proposed to allow CSAPR as an alternative to the source-specific BART determinations. However, the original BART NO_X emissions limit was later replaced with a more stringent NO_X emissions limit (0.06 lb NO_X/MMBtu as a 30-day rolling average) established within a consent decree between Minnesota Power, the United States of America, and the State of Minnesota.[103] This emission unit is also currently subject to, and complying with, the applicable alternative SO_2 limit established in the MATS rule for existing coal-fired EGUs (0.20 lb SO_2/MMBtu) through the use of add-on flue gas desulfurization (FGD).

These circumstances are specific examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[104] Regarding NO_X emissions, the emission unit installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, the emission unit is an EGU that has add-on FGD and meets the applicable alternative SO_2 emission limit in the MATS rule. Given the level of control required for this emission unit, the MPCA determined that it was unlikely that there are further available reasonable controls for this emission unit and removed it from further analysis for this implementation period.

Minnesota Power - Boswell Unit 4 is equipped with low-NO_X burners, overfire air controls, and selective non-catalytic reduction (SNCR) for NO_X control, a semi-dry FGD system for SO_2 and acid gas control, and a fabric filter with activated carbon injection for $PM/PM_{10}/PM_{2.5}$ and mercury control.

This emission unit is subject to a NO_X emissions limit (0.12 lb NO_X/MMBtu as a 30-day rolling average) established within the previously described consent decree between Minnesota Power, the United States of America, and the State of Minnesota.[105] While this limit was not established as a result of a BACT evaluation, Minnesota Power conducted a search of U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) , available in Appendix B. Four-Factor Analyses - Facility Responses, and provided the results showing that the NO_X emissions limit was more stringent than the recent evaluations for similar sources. This emission unit is also currently subject to, and complying with, the applicable alternative SO_2 limit

[103] *See* Consent Decree, U.S. v. Minn. Power, No. 0:14-cv-2911-ADM-LIB (D. Minn. Filed July 16, 2014) https://www.epa.gov/sites/default/files/2014-07/documents/minnesotapower-cd.pdf.
[104] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 22-25.
[105] *See* Consent Decree, U.S. v. Minn. Power, No. 0:14-cv-2911-ADM-LIB (D. Minn. Filed July 16, 2014).

established in the MATS rule for existing coal-fired EGUs (0.20 lb SO_2/MMBtu) through the use of add-on flue gas desulfurization (FGD).

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., EGUs with add-on FGD that meet the applicable SO_2 limits of the MATS rule).[106] Regarding NO_X emissions, while the emission unit did not go through BACT, the NO_X emissions limit is more stringent than other NO_X evaluations for similar sources. Regarding SO_2 emissions, the emission unit is an EGU that has add-on FGD and meets the applicable alternative SO_2 emission limit in the MATS rule. Given the level of control required for this emission unit, the MPCA determined that it was unlikely that there are further available reasonable controls for this emission unit and removed it from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 36. Minnesota Power - Boswell Energy Center, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Unit 3						
Heat Input (MMBtu)	24,698,776	24,746,826	24,421,528	17,153,037	16,990,166	-
NO_X emissions (tons)	705.95	738.07	722.85	480.36	498.61	793.96
NO_X emission rate (lb/MMBtu)	0.06	0.06	0.06	0.06	0.06	-
SO_2 emissions (tons)	137.58	130.53	164.81	117.49	113.88	154.65
SO_2 emission rate (lb/MMBtu)	0.01	0.01	0.01	0.01	0.01	-
Unit 4						
Heat Input (MMBtu)	44,981,900	41,795,773	43,077,431	35,196,218	29,118,111	-
NO_X emissions (tons)	2,610.88	2,414.92	2,490.11	1,873.21	1,540.20	2,876.13
NO_X emission rate (lb/MMBtu)	0.12	0.12	0.12	0.11	0.11	-
SO_2 emissions (tons)	553.50	604.48	598.81	459.41	377.11	609.74
SO_2 emission rate (lb/MMBtu)	0.02	0.03	0.03	0.03	0.03	-

While the projected emissions for 2028 are higher than reported emissions for all years displayed, the facility has been implementing the existing controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above. MPCA has no reason to believe that

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

emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

Northshore Mining - Silver Bay. Indurating Furnaces 11 and 12 at Northshore Mining - Silver Bay were BART-eligible emission units and BART emission limits on NO_X and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first regional haze implementation period. These furnaces are only capable of burning natural gas and fuel oil. Both emission units are controlled by wet electrostatic precipitators (ESP) using caustic reagent for SO_2 control.

These emission units are subject to a NO_X emissions limit (1.2-1.5 lb NO_X/MMBtu for each furnace, fuel dependent, as a 30-day rolling average) established in the Taconite FIP dated February 6, 2013. However, these emission units did not require add-on controls to meet the NO_X limits as the furnaces' design utilizes burners critically located to provide heat to the various furnace sections. These emission units are also subject to an SO_2 emissions limit (39.0 lb SO_2/hr for both furnaces combined as a 30-day rolling average) established in the Taconite FIP dated February 6, 2013. The primary source of SO_2 emissions is from trace amounts of sulfur present in the iron concentrate and binding agents. In the 2013 Taconite FIP, U.S. EPA determined that because Northshore is burning natural gas and fuel oil, with natural gas as the primary fuel, additional SO_2 controls were not economically reasonable and were not necessary for BART.

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[107] Regarding NO_X emissions, the emission units installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission units were determined to be BART, meaning no add-on controls were required, the emission units primarily burn natural gas that is inherently low in sulfur. Given the level of control required for these emission units, the MPCA determined that it was unlikely that there are further available reasonable controls for these emission units and removed them from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu or lb/ton pellet) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu or ton pellet) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 37. Northshore Mining - Silver Bay, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Furnace 11						
Heat Input (MMBtu)	665,424	1,043,674	1,090,928	1,059,072	312,326	-

[107] *See id.*

Parameter	2016	2017	2018	2019	2020	2028 Model
Pellet Production (tons)	1,268,953	2,055,015	2,247,020	2,023,932	1,479,093	-
NO_X emissions (tons)	165.05	266.62	322.15	253.28	223.27	267.34
NO_X emission rate (lb/MMBtu)	0.50	0.51	0.59	0.48	1.43	-
NO_X emission rate (lb/ton pellet)	0.26	0.26	0.29	0.25	0.30	-
SO_2 emissions (tons)	45.30	73.36	80.22	72.26	52.80	73.56
SO_2 emission rate (lb/MMBtu)	0.14	0.14	0.15	0.14	0.34	-
SO_2 emission rate (lb/ton pellet)	0.07	0.07	0.07	0.07	0.07	-
Furnace 12						
Heat Input (MMBtu)	741,514	1,068,496	1,010,122	1,056,376	755,836	-
Pellet Production (tons)	1,415,082	2,083,148	2,087,370	1,938,074	1,431,893	-
NO_X emissions (tons)	219.12	318.65	331.68	279.25	228.96	319.51
NO_X emission rate (lb/MMBtu)	0.59	0.60	0.66	0.53	0.61	-
NO_X emission rate (lb/ton pellet)	0.31	0.31	0.32	0.29	0.32	-
SO_2 emissions (tons)	50.52	74.36	74.52	69.18	51.12	74.56
SO_2 emission rate (lb/MMBtu)	0.14	0.14	0.15	0.13	0.14	-
SO_2 emission rate (lb/ton pellet)	0.07	0.07	0.07	0.07	0.07	-

While the projected NO_X emissions for 2028 are higher than reported emissions for some years displayed, the facility has been working to implement the controls described earlier resulting in a reasonably consistent NO_X emission rate over the most recent five years displayed above. While the projected SO_2 emissions for 2028 are higher than reported emissions for some years displayed, the facility has been implementing the controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above.

While there is an increase in the NO_X and SO_2 emission rates for Furnace 11 in 2020, this is likely due to the effects of the Covid-19 Pandemic that caused many facilities to slow or idle production. MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

Sappi Cloquet. Sappi Cloquet's Recovery Boiler #10 burns strong black liquor solids (BLS) that are generated in the Kraft pulp mill chemical recovery process. Weak BLS, which are generated as part of the pulping and washing processes, are concentrated in evaporators to make strong BLS. The strong BLS are then charged to the recovery boiler where the organic portion of the BLS is burned to produce steam to generate electricity and provide heat for other processes at the plant. The combustion process results in emissions of NO_X and other pollutants. The emission unit uses a high-efficiency electrostatic precipitator (ESP) to control particulate matter emissions and quaternary air injection to manage the generation of NO_X emissions.

This emission unit underwent a BACT review for NO_X emissions that established a NO_X emissions limit as part of a construction permit (Air Emissions Permit No. 01700002-101) issued on June 30, 2017. The NO_X emission limits established were 100 ppm by volume (dry) NO_X, corrected to 8% oxygen, as a 30-day rolling average and 241 lb/hr NO_X.

These circumstances are specific examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., an emission unit that went through a BACT review).[108] Regarding NO_X emissions, the emission unit went through a BACT review after July 31, 2013. Given the level of control required for this emission unit, the MPCA determined that it was unlikely that there are further available reasonable controls for this emission unit and removed it from further analysis.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 38. Sappi Cloquet, NO_X emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Recovery Boiler #10						
Heat Input (MMBtu)	9,556,193	9,745,731	10,128,357	10,385,558	9,929,145	-
NO_X emissions (tons)	703.90	746.90	723.00	680.40	658.00	705.83
NO_X emission rate (lb/MMBtu)	0.15	0.15	0.14	0.13	0.13	-

While the projected emissions for 2028 are lower than reported emissions for some years displayed, the facility has been implementing the existing controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above. MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

United Taconite - Fairlane Plant. Lines 1 and 2 at United Taconite were BART-eligible emission units and BART emission limits on NO_X and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first regional haze implementation period. Lines 3, 4, and 5 can burn coal, petroleum coke, natural gas, and distillate oil. These emission units utilize existing wet scrubbers for SO_2 control.

These emission units are subject to a NO_X emissions limit (1.5-3.0 lb NO_X/MMBtu for each line, fuel dependent, as a 30-day rolling average) established in the Taconite FIP dated April 12, 2016. These emission units required add-on controls (low NO_X burners) to meet the NO_X limits. These emission units are also subject to an SO_2 emissions limit (529 lb SO_2/hr, averaged across both lines as a 30-day rolling average and a 1.50 percent sulfur content limit for any coal burned as a monthly block average)

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[108] *See id.*

established in the Taconite FIP dated April 12, 2016. In the 2016 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[109] Regarding NO_X emissions, the emission units installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission units were determined to be BART, meaning no add-on controls were required, both emission units are subject to an hourly SO_2 emission rate limit and fuel sulfur content requirements established in the Taconite FIP. Given the level of control required for these emission units, the MPCA determined that it was unlikely that there are further available reasonable controls for these emission units and removed them from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu or lb/ton pellet) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu or ton pellet) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 39. United Taconite - Fairlane Plant, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Line 1 Pellet Induration						
Heat Input (MMBtu)	309,207	1,195,604	1,387,514	1,353,678	1,442,714	-
Pellet Production (tons)	533,279	1,789,545	2,042,125	2,138,667	2,010,929	-
NO_X emissions (tons)	504.60	1,341.80	1,414.40	1,383.50	1,198.00	1,330.47
NO_X emission rate (lb/MMBtu)	3.26	2.24	2.04	2.04	1.66	-
NO_X emission rate (lb/ton pellet)	1.89	1.50	1.39	1.29	1.19	-
SO_2 emissions (tons)	79.96	59.72	104.13	109.63	87.72	60.67
SO_2 emission rate (lb/MMBtu)	0.52	0.10	0.15	0.16	0.12	-
SO_2 emission rate (lb/ton pellet)	0.30	0.07	0.10	0.10	0.09	-
Line 2 Pellet Induration						
Heat Input (MMBtu)	907,076	2,033,156	2,305,286	2,618,174	2,393,862	-
Pellet Production (tons)	1,200,924	3,618,933	3,802,794	3,793,590	3,865,612	-

[109] *See id.*

Parameter	2016	2017	2018	2019	2020	2028 Model
NO_X emissions (tons)	505.30	2,399.60	3,372.70	3,396.50	3,146.90	1,885.05
NO_X emission rate (lb/MMBtu)	1.11	2.36	2.93	2.59	2.63	-
NO_X emission rate (lb/ton pellet)	0.84	1.33	1.77	1.79	1.63	-
SO_2 emissions (tons)	87.01	215.43	260.69	239.49	354.43	217.47
SO_2 emission rate (lb/MMBtu)	0.19	0.21	0.23	0.18	0.30	-
SO_2 emission rate (lb/ton pellet)	0.14	0.12	0.14	0.13	0.18	-

The projected NO_X emissions for 2028 are lower than reported emissions for some years displayed as the facility has been working to implement the controls described earlier resulting in a decreasing NO_X emission rate for Line 1 over the most recent five years displayed above. Additionally, the most recent years of NO_X emissions data highlights the expected NO_X emission reductions due to the Regional Haze Taconite FIP. The NO_X emission rate for Line 2 has not yet seen a similar decrease as Line 1, as the facility is still going through settlement discussions with U.S. EPA regarding the Regional Haze Taconite FIP as described in Section 1.3 regarding the NO_X controls described earlier. However, MPCA expects additional NO_X emission reductions due to these requirements as shown in the projected 2028 NO_X emissions for Line 2. Additional detail regarding how MPCA estimated the expected reductions due to the Regional Haze Taconite FIP is available in Section 2.6.1. While the projected SO_2 emissions for 2028 are lower than reported emissions for some years displayed, the facility has been implementing the controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above.

Note that emissions increase between 2016 and 2017 due to the emission units operating at reduced capacity in 2016 (as shown by the lower pellet production for 2016 compared to other years). MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

U.S. Steel - Keetac. The indurating furnace at U.S. Steel - Keetac was a BART-eligible emission unit and BART emission limits on NO_X and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first regional haze implementation period. The emission unit can burn coal, petroleum coke, natural gas, and distillate oil. This emission unit utilizes existing wet scrubbers for SO_2 control.

This emission unit is subject to a NO_X emissions limit (1.2-1.5 lb NO_X/MMBtu, fuel dependent, as a 30-day rolling average) established in the Taconite FIP dated February 6, 2013. This emission unit required add-on controls (low NO_X burners) to meet the NO_X limits. This emission unit is also subject to an SO_2 emissions limit (225 lb SO_2/hr as a 30-day rolling average and a 0.60 percent sulfur content limit for any coal burned as a monthly block average) established in the Taconite FIP dated February 6, 2013. In the 2013 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[110] Regarding NO_X emissions, the emission unit installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission unit were determined to be BART, meaning no add-on controls were required, the emission unit is subject to an hourly SO_2 emission rate limit and fuel sulfur content requirements established in the Taconite FIP. Given the level of control required for this emission unit, the MPCA determined that it was unlikely that there are further available reasonable controls for this emission unit and removed it from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu or lb/ton pellet) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu or ton pellet) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 40. U.S. Steel - Keetac, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Line 1 Pellet Induration						
Heat Input (MMBtu)	-	2,003,400	2,578,800	2,695,350	1,011,255	-
Pellet Production (tons)	-	5,076,095	5,841,492	5,763,953	2,036,392	-
NO_X emissions (tons)	-	5,009.00	5,005.00	3,306.00	1,388.00	1,372.81
NO_X emission rate (lb/MMBtu)	-	5.00	3.88	2.45	2.75	-
NO_X emission rate (lb/ton pellet)	-	1.97	1.71	1.15	1.36	-
SO_2 emissions (tons)	-	533.00	636.50	675.30	247.50	537.04
SO_2 emission rate (lb/MMBtu)	-	0.53	0.49	0.50	0.49	-
SO_2 emission rate (lb/ton pellet)	-	0.21	0.22	0.23	0.24	-

The projected NO_X emissions for 2028 are lower than reported emissions for some years displayed as the facility has been working to implement the controls described earlier resulting in a decreasing NO_X emission rate over the most recent five years displayed above. Additionally, the most recent years of NO_X emissions data highlights the expected NO_X emission reductions due to the Regional Haze Taconite FIP. Additional detail regarding how MPCA estimated the expected reductions due to the Regional Haze Taconite FIP is available in Section 2.6.1. While the projected SO_2 emissions for 2028 are lower than reported emissions for some years displayed, the facility has been implementing the controls described

[110] *See id.*

earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above.

Note that there is no emissions data for 2016 as the facility was not operating that year. While there is an increase in the NO_X emission rates in 2020, this is likely due to the effects of the Covid-19 Pandemic that caused many facilities to slow or idle production and skew the annual average emission rates (as shown by the lower pellet production for 2020 compared to other years). MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

U.S. Steel - Minntac. Lines 3, 4, 5, 6, and 7 at U.S. Steel - Minntac were BART-eligible emission units and BART emission limits on NO_X and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first regional haze implementation period. Lines 3, 4, and 5 can burn natural gas, wood, and fuel oil, but natural gas and wood are used most frequently. Since these fuels are low in sulfur, the primary source of sulfur in these furnaces is the iron ore used to form the taconite pellets. Additional sulfur may be present in the additives used in the taconite pellets. In addition to natural gas, wood, and fuel oil, coal is used in Lines 6 and 7. These emission units are controlled by existing wet scrubbers that are estimated to remove 15-30 percent of the SO_2 in the exhaust gas.

These emission units are subject to a NO_X emissions limit (1.6 lb NO_X/MMBtu averaged across all five lines as a 30-day rolling average) established in the Taconite FIP dated April 1, 2021. These emission units required add-on controls (low NO_X burners) to meet the NO_X limits. These emission units are also subject to an SO_2 emissions limit (498-800 lb SO_2/hr, dependent on the type of pellet produced by each line, averaged across all five lines as a 30-day rolling average and a 0.60 percent sulfur content limit for any coal burned as a monthly block average) established in the Taconite FIP dated February 6, 2013. In the 2013 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

These circumstances are specific, or similar to, examples U.S. EPA identifies in its August 2019 Guidance where it may be reasonable to not select a source for further analysis (i.e., BART-eligible emission units meeting BART limits for the first regional haze implementation period on a pollutant specific basis).[111] Regarding NO_X emissions, the emission units installed and began operating controls to meet BART emission limits for the first implementation period. Regarding SO_2 emissions, while the existing controls for the emission units were determined to be BART, meaning no add-on controls were required, Lines 3, 4, and 5 primarily burn fuels that are inherently low in sulfur and all emission units are subject to an hourly SO_2 emission rate limit and fuel sulfur content requirements established in the Taconite FIP. Given the level of control required for these emission units, the MPCA determined that it was unlikely that there are further available reasonable controls for these emission units and removed them from further analysis for this implementation period.

Furthermore, the MPCA reviewed the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020 to analyze the existing control measures to help inform the expected future operations of these emission units. The table below summarizes the emissions data, as reported to Minnesota's annual emissions inventory, for the emission units discussed above. Emission rates (in lb/MMBtu or lb/ton pellet) in the table are calculated directly from the annual emissions (converted to pounds) and throughput values (MMBtu or ton pellet) and represent an overall annual average for the years displayed. Projected 2028 emissions for the emission units are also displayed for

[111] *See id.*

comparison to the other years of emissions data, but there is not throughput data available from the model, so an emission rate cannot be calculated nor can a direct comparison to historical emission rates be made.

Table 41. U.S. Steel - Minntac, NO_X and SO_2 emissions data

Parameter	2016	2017	2018	2019	2020	2028 Model
Line 3 Rotary Kiln						
Heat Input (MMBtu)	1,584,445	1,576,417	1,546,022	1,062,053	1,425,008	-
Pellet Production (tons)	1,957,518	1,907,339	1,995,365	1,406,243	1,956,638	-
NO_X emissions (tons)	1,122.92	1,020.69	962.57	718.71	1,012.60	723.60
NO_X emission rate (lb/MMBtu)	1.42	1.29	1.25	1.35	1.42	-
NO_X emission rate (lb/ton pellet)	1.15	1.07	0.96	1.02	1.04	-
SO_2 emissions (tons)	306.53	269.13	331.60	193.56	266.97	308.07
SO_2 emission rate (lb/MMBtu)	0.39	0.34	0.43	0.36	0.37	-
SO_2 emission rate (lb/ton pellet)	0.31	0.28	0.33	0.28	0.27	-
Line 4 Rotary Kiln						
Heat Input (MMBtu)	1,896,712	2,333,461	2,141,166	1,984,422	2,149,298	-
Pellet Production (tons)	3,101,681	3,395,051	3,380,930	3,177,555	3,218,663	-
NO_X emissions (tons)	1,900.97	1,357.10	1,117.80	1,192.90	1,374.36	1,294.34
NO_X emission rate (lb/MMBtu)	2.00	1.16	1.04	1.20	1.28	-
NO_X emission rate (lb/ton pellet)	1.23	0.80	0.66	0.75	0.85	-
SO_2 emissions (tons)	224.52	273.50	208.74	141.10	210.75	227.01
SO_2 emission rate (lb/MMBtu)	0.24	0.23	0.19	0.14	0.20	-
SO_2 emission rate (lb/ton pellet)	0.14	0.16	0.12	0.09	0.13	-
Line 5 Rotary Kiln						
Heat Input (MMBtu)	2,235,293	2,267,899	2,432,076	2,283,187	2,288,842	-
Pellet Production (tons)	3,367,410	3,299,808	3,320,755	3,393,523	3,248,730	-
NO_X emissions (tons)	1,184.35	1,263.70	1,393.70	1,420.90	1,417.90	788.35
NO_X emission rate (lb/MMBtu)	1.06	1.11	1.15	1.24	1.24	-
NO_X emission rate (lb/ton pellet)	0.70	0.77	0.84	0.84	0.87	-
SO_2 emissions (tons)	268.77	287.00	206.32	154.50	174.10	272.49
SO_2 emission rate (lb/MMBtu)	0.24	0.25	0.17	0.14	0.15	-
SO_2 emission rate (lb/ton pellet)	0.16	0.17	0.12	0.09	0.11	-

Parameter	2016	2017	2018	2019	2020	2028 Model
Line 6 Rotary Kiln						
Heat Input (MMBtu)	2,001,300	2,347,105	2,236,424	1,980,538	1,917,771	-
Pellet Production (tons)	3,165,842	3,875,911	3,638,690	3,148,009	3,009,392	-
NO_X emissions (tons)	999.50	1,224.80	1,092.36	1,161.49	1,181.97	675.39
NO_X emission rate (lb/MMBtu)	1.00	1.04	0.98	1.17	1.23	-
NO_X emission rate (lb/ton pellet)	0.63	0.63	0.60	0.74	0.79	-
SO_2 emissions (tons)	106.00	152.36	140.10	155.38	96.68	108.50
SO_2 emission rate (lb/MMBtu)	0.11	0.13	0.13	0.16	0.10	-
SO_2 emission rate (lb/ton pellet)	0.07	0.08	0.08	0.10	0.06	-
Line 7 Rotary Kiln						
Heat Input (MMBtu)	2,069,550	2,329,950	2,599,800	2,306,337	1,780,800	-
Pellet Production (tons)	3,423,365	3,503,005	3,588,270	3,324,274	2,656,640	-
NO_X emissions (tons)	1,074.00	1,497.00	1,519.00	1,088.42	859.40	680.10
NO_X emission rate (lb/MMBtu)	1.04	1.29	1.17	0.94	0.97	-
NO_X emission rate (lb/ton pellet)	0.63	0.85	0.85	0.65	0.65	-
SO_2 emissions (tons)	243.30	224.30	164.70	157.96	155.30	244.09
SO_2 emission rate (lb/MMBtu)	0.24	0.19	0.13	0.14	0.17	-
SO_2 emission rate (lb/ton pellet)	0.14	0.13	0.09	0.10	0.12	-

U.S. EPA only recently finalized the limits for this facility identified in the Regional Haze Taconite FIP, as described previously in Section 1.3 regarding the NO_X controls described earlier. However, MPCA expects additional NO_X emission reductions due to these requirements as shown in the projected 2028 NO_X emissions. Additional detail regarding how MPCA estimated the expected reductions due to the Regional Haze Taconite FIP is available in Section 2.6.1. While the projected SO_2 emissions for 2028 are lower or higher than reported emissions for some years displayed, depending on the emission unit, the facility has been implementing the controls described earlier resulting in a reasonably consistent emission rate over the most recent five years displayed above.

MPCA has no reason to believe that emission rates for these emission units will increase in the future given that the applicable limits, control equipment, and associated requirements are already enforceable requirements as shown in Table 32.

2.3.6. Documentation of the source selection process and result

Originally, the MPCA selected 13 stationary sources with emission units that represent roughly the top 80% of stationary source emissions from Minnesota sources that may impact visibility based on the Q/d analysis for Boundary Waters and Voyageurs. The MPCA chose to use a threshold of 80% based on it being a reasonably large fraction of in-state contributions to visibility from stationary sources and selecting this large fraction of stationary sources ensures that MPCA analyzes a sufficient number of sources in light of the statutory requirement to make reasonable progress towards natural visibility. A threshold of 80% was also the recommended screening threshold level for visibility impacts in U.S. EPA's draft June 2016 guidance for regional haze implementation plans for the second implementation period.[112]

Furthermore, MPCA was aware that some of the sources within the top 80% would already have effective control technology in place prior to 2028 or emissions reductions expected (e.g., on-the-books controls, expected retirement dates, etc.) due to other enforceable requirements. MPCA's methodology to select the top 80% of stationary source emissions also ensured that a reasonably inclusive set of sources was examined; and that sources with potential for visibility benefits from the control measure analysis are examined in this implementation period, not just those sources that had planned, or already realized, emission reductions through strategies contemplated outside the regional haze program.

On January 29, 2020, the MPCA sent a Request for Information (RFI) letter to 13 facilities, identified in Table 27, requesting that they conduct a four-factor analysis. To identify which emission units were requested to conduct a four-factor analysis, the MPCA relied on the annual emissions data broken up into the process level emissions for each facility. The Q/d values described below were not used to identify the selected facilities, but to inform which sources at those facilities were the focus of the four-factor analysis request. Generally, sources were categorized as high, medium, or low priority based on their process specific Q/d values, where high priority is Q/d greater than four, medium priority is Q/d between four and one, and low priority is Q/d less than one. As a region, the LADCO states decided to focus on sources within the high and medium priority categories for gathering control information and possibly requesting a four-factor analysis. The sources selected for Minnesota included values as low as 1.3 to account for emission units that have emissions broken up into multiple process IDs (e.g., one facility might have eight process IDs for their emission unit that covers different products and/or fuels used).

MPCA also discussed the selection of sources as part of consultation with the Federal Land Managers (FLMs). As discussed above, the MPCA had originally applied the Q/d analysis on an individual emission unit basis, still using the top 80% of stationary source emissions as a cutoff threshold, in the selection of the 13 facilities and specific emission units of interest at those facilities. This step used an effective Q/d threshold of 7. The FLMs identified specific facilities of interest using their own criteria that they provided MPCA for consideration in the source selection step. During this discussion, the FLMs identified that they did not believe a Q/d analysis should be applied to individual emission units at a subdivided facility, but should be applied to the total emissions from a facility.

However, MPCA and the FLMs agreed that considering emission levels at individual emission units was reasonable when contemplating the feasibility of additional controls from the control measure analysis. As one example for this scenario, the FLMs indicated that once a facility had exceeded their Q/d threshold, they looked at the current levels of control to determine if additional controls were potentially feasible (e.g., if highly efficient wet scrubbers were operating as well as could be expected, no further analyses would be needed). After further reviewing U.S. EPA's August 2019 Guidance, MPCA agreed that applying the Q/d analysis at a facility level, instead of an emission unit level, was more appropriate and redid the Q/d analysis on a facility level basis.

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[112] U.S. EPA, Draft Guidance on Process Tracking Merits, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Period 72 (July 2016), https://www.epa.gov/sites/default/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf.

Afterwards, the MPCA sent a revised RFI letter to one of the original 13 facilities (Northshore Mining Company) and RFI letters to four additional facilities that were identified as facilities of interest by the FLMs on February 14, 2020 (American Crystal Sugar - Crookston, American Crystal Sugar - East Grand Forks, Hibbing Public Utilities Commission, and Southern Minnesota Beet Sugar Cooperative). MPCA did not send RFI letters to all facilities of interest identified by the FLMs, but the inclusion of the four additional sources was based on the above consideration to include a sufficient set of sources in the source selection step with potential for visibility benefits from the control measure analysis. With the inclusion of these additional sources, the MPCA selected sources for analysis that correspond to roughly the top 85% of stationary source emissions from Minnesota sources that may impact visibility based on the Q/d Analysis for both the Boundary Waters and Voyageurs Class I areas. Adding these four facilities resulted in an effective Q/d threshold of 4.6.

The tables below summarize which facilities and emission units the MPCA requested to conduct a four-factor analysis and the facilities of interest identified by the FLMs. Each table includes the list of facilities, organized by descending Q/d value, down to the facility with the smallest Q/d value that was identified by an FLM as a facility of interest to them (e.g., for both tables Duluth Steam Plant 1 is the facility with the lowest Q/d value and was identified by the U.S. Forest Service as a facility of interest). Other facilities that have a higher Q/d value, which were not selected by MPCA in this step, nor identified by the FLMs as a facility of interest, are also included to provide a complete overview of the facilities with the highest Q/d values for the Boundary Waters and Voyageurs Class I areas. This information is identified to provide the information needed to determine the percentile (percent of the total Q/d for the Class I area) and cumulative percentile for the respective Class I area.

Table 42. Boundary Waters four-factor analysis source selection overview

Facility name	Q/d	Percentile	Cumulative percentile	FLM interest	Four-Factor Analysis requested?
US Steel Corp - Minntac	99.71	15.86%	15.86%	USFS/NPS	Yes
Northshore Mining Co - Silver Bay	53.61	8.53%	24.39%	USFS/NPS	Yes
Xcel Energy - Sherburne Generating Plant	52.15	8.30%	32.69%	USFS/NPS	Yes
Minnesota Power Inc - Boswell Energy Ctr	51.47	8.19%	40.88%	USFS/NPS	Yes
Hibbing Taconite Co	46.06	7.33%	48.20%	USFS/NPS	Yes
US Steel Corp - Keetac	45.53	7.24%	55.45%	USFS/NPS	Yes
United Taconite LLC - Fairlane Plant	42.72	6.80%	62.24%	USFS/NPS	Yes
Cleveland Cliffs Minorca Mine Inc	40.07	6.37%	68.62%	USFS/NPS	Yes
Minnesota Power - Taconite Harbor Energy Center	20.59	3.28%	71.89%		Yes
Sappi Cloquet LLC	11.56	1.84%	73.73%	USFS/NPS	Yes
Xcel Energy - Allen S King Generating Plant	9.46	1.50%	75.24%	USFS/NPS	Yes
Virginia Department of Public Utilities	7.91	1.26%	76.50%	USFS/NPS	Yes
Minneapolis-St Paul International Airport	7.53	1.20%	77.69%		No
Hibbing Public Utilities Commission	7.47	1.19%	78.88%	USFS/NPS	Yes
Flint Hills Resources Pine Bend Refinery	7.43	1.18%	80.06%	USFS/NPS	No
Boise White Paper LLC - Intl Falls	7.16	1.14%	81.20%	USFS/NPS	Yes
American Crystal Sugar - Crookston	6.12	0.97%	82.18%	USFS/NPS	Yes

Facility name	Q/d	Percentile	Cumulative percentile	FLM interest	Four-Factor Analysis requested?
Blandin Paper Co/MN Power - Rapids Energy Center	5.06	0.80%	82.98%	USFS	No
American Crystal Sugar - East Grand Forks	4.85	0.77%	83.75%	USFS/NPS	Yes
Southern Minnesota Beet Sugar Coop	4.62	0.74%	84.49%	USFS/NPS	Yes
Minnesota Power - Hibbard Renewable Energy Ctr	4.60	0.73%	85.22%	USFS	No
Otter Tail Power Co	3.46	0.55%	85.77%		No
Anchor Glass Container Corp	3.23	0.51%	86.29%	USFS	No
Northshore Mining Co - Babbitt	3.08	0.49%	86.78%	USFS	No
American Crystal Sugar - Moorhead	3.07	0.49%	87.27%	USFS	No
Duluth Steam Plant 1	3.06	0.49%	87.75%	USFS	No

Additional information regarding why certain facilities of interest identified by the FLMs were not selected for an analysis of control measures in this implementation period is provided after Table 43.

Table 43. Voyageurs four-factor analysis source selection overview

Facility name	Q/d	Percentile	Cumulative percentile	FLM interest	Four-Factor Analysis requested?
US Steel Corp - Minntac	99.13	16.06%	16.06%	USFS/NPS	Yes
Minnesota Power Inc - Boswell Energy Ctr	64.81	10.50%	26.56%	USFS/NPS	Yes
Hibbing Taconite Co	53.68	8.70%	35.26%	USFS/NPS	Yes
US Steel Corp - Keetac	53.24	8.63%	43.89%	USFS/NPS	Yes
Xcel Energy - Sherburne Generating Plant	50.99	8.26%	52.15%	USFS/NPS	Yes
United Taconite LLC - Fairlane Plant	37.40	6.06%	58.21%	USFS/NPS	Yes
Cleveland Cliffs Minorca Mine Inc	36.03	5.84%	64.05%	USFS/NPS	Yes
Boise White Paper LLC - Intl Falls	23.92	3.88%	67.92%	USFS/NPS	Yes
Northshore Mining Co - Silver Bay	23.62	3.83%	71.75%	USFS/NPS	Yes
Sappi Cloquet LLC	9.31	1.51%	73.26%	USFS/NPS	Yes
Xcel Energy - Allen S King Generating Plant	8.52	1.38%	74.64%	USFS/NPS	Yes
Hibbing Public Utilities Commission	8.33	1.35%	75.99%	USFS/NPS	Yes
American Crystal Sugar - Crookston	8.06	1.31%	77.29%	USFS/NPS	Yes
Minnesota Power - Taconite Harbor Energy Center	7.56	1.22%	78.52%		Yes
Virginia Department of Public Utilities	7.13	1.16%	79.67%	USFS/NPS	Yes
Minneapolis-St Paul International Airport	6.99	1.13%	80.80%		No
Flint Hills Resources Pine Bend Refinery	6.82	1.11%	81.91%	USFS/NPS	No
American Crystal Sugar - East Grand Forks	6.34	1.03%	82.94%	USFS/NPS	Yes
Blandin Paper Co/MN Power - Rapids Energy Center	6.17	1.00%	83.94%	USFS	No
Southern Minnesota Beet Sugar Coop	4.72	0.77%	84.70%	USFS/NPS	Yes

Facility name	Q/d	Percentile	Cumulative percentile	FLM interest	Four-Factor Analysis requested?
Otter Tail Power Co	4.00	0.65%	85.35%		No
American Crystal Sugar - Moorhead	3.74	0.61%	85.96%	USFS	No
Minnesota Power - Hibbard Renewable Energy Ctr	3.41	0.55%	86.51%	USFS	No
Anchor Glass Container Corp	3.05	0.49%	87.00%	USFS	No
Saint Paul Park Refining Co LLC	2.60	0.42%	87.42%		No
Andersen Corp	2.41	0.39%	87.81%		No
Duluth Steam Plant 1	2.21	0.36%	88.17%	USFS	No

While the MPCA requested that these sources prepare and submit an analysis of control measures for certain emission units, some facilities were removed from further analysis due to the effectively controlled determinations discussed in Section 2.3.5 or the proposed retirements discussed in Section 2.3.3. Additional information regarding why certain facilities of interest identified by the FLMs were not selected for an analysis of control measures in this implementation period is provided below.

Minneapolis - St. Paul International Airport. The majority of emissions from the Minneapolis - St. Paul International Airport (MSP Airport) can be attributed to aircraft takeoffs and landings. These emissions are regulated by emission standards set by U.S. EPA, and the Federal Aviation Administration (FAA) sets and administers the certification requirements for aircraft and engines to demonstrate compliance with the emission standards. Emission standards developed by U.S. EPA are specified in 40 CFR Part 87, Control of Air Pollution from Aircraft and Aircraft Engines. Furthermore, states and local units of government are prohibited from adopting their own emission standards, as specified in 40 CFR § 87.3(d), unless they are identical to the federal standards. As a result, the MPCA removed the MSP Airport from further analysis given that Minnesota does not have the authority to establish additional emission standards for aircraft and aircraft engines.

Flint Hills Resources Pine Bend Refinery. Flint Hills Resources Pine Bend Refinery is a petroleum refinery located in Rosemount, Minnesota that processes heavy, sour crude oil from Western Canada and oil from other parts of the world, to produce various petroleum products including gasoline, diesel fuel, heating oil, jet fuel, petroleum coke, asphalt, and elemental sulfur. This facility was identified by both the US F.S. and U.S. NPS, but the MPCA did not select this facility due to the emissions being dispersed across multiple individual emission units at the facility. While the facility was ranked in the top 85% of emissions from Minnesota sources in the Q/d analysis, those emissions were broken up over 63 different emission units at the facility. Each of those individual emission units at the facility had a Q/d value of less than one, the highest value for any emission unit being 0.89 followed by 11 emission units between 0.10 and 0.54, and the remaining emission units below 0.10. Given the distributed nature of emissions across these emission units, MPCA estimated a low likelihood that the outcome of a control measure analysis would result in a determination of feasible controls. This should not be construed to mean that the MPCA has made the determination that there are no feasible controls for this facility. However, to distribute the analytical work needed for the regional haze program across multiple implementation periods, the MPCA decided to not select this source for an analysis of control measures in this implementation period.

Blandin Paper Company / Minnesota Power - Rapids Energy Center. Blandin Paper Company and Minnesota Power operate a pressurized groundwood pulp mill and paper facility in Grand Rapids, Minnesota. Blandin Paper operates the pulp and paper mill while Minnesota Power operates the steam and electricity generation facility. On January 11, 2019, Minnesota Power provided a notification to

MPCA that, for economic reasons, Minnesota Power idled the two biomass- and coal-fired boilers, Boiler #5 (EQUI 1 / EU 003) and Boiler #6 (EQUI 3 / EU 003) at the Rapids Energy Center facility. Minnesota Power has stated that these boilers will remain in an idled (not retired) status for the foreseeable future, and while they will not operate continuously, they will be maintained and ready for restart when needed.

The majority of NO_X and SO_2 emissions from the facility are attributed to the boilers, which are represented by the steep decline in recent years of reported actual emissions. For reference, NO_X emissions from the facility ranged from 377 to 432 tons per year in 2016-2018 declining to 28 to 32 tons per year in 2019-2020. Similarly, SO_2 emissions also declined from 61 to 69 tons per year in 2016-2018 to 0.5 to 1.5 tons per year in 2019-2020. Given the uncertainty in future operating status of these two boilers, the MPCA chose to not select this source for analysis in this implementation period. If these boilers increase operations in the future, Minnesota may reevaluate this facility for the progress report or third implementation period.

Minnesota Power - Hibbard Renewable Energy Center. Minnesota Power's Hibbard Renewable Energy Center is a steam and power generation facility that primarily produces steam for the Verso Paper Mill located in Duluth, Minnesota, but can also produce electricity for the Minnesota Power system. The primary sources of NO_X and SO_2 emissions at the facility are the four boilers used to produce heat and power.

However, in June 2020 the Verso Paper Mill announced that it would be indefinitely idled by the end of the month. It is unclear what this means regarding operations of Minnesota Power - Hibbard Renewable Energy Center at this time. Given the uncertainty of future operations, and to distribute the analytical work needed for the regional haze program across multiple implementation periods, the MPCA decided to not select this source for an analysis of control measures in this implementation period. If these boilers increase operations in the future, Minnesota may reevaluate this facility for the progress report or third implementation period.

Otter Tail Power. Otter Tail Power is a power generation facility located in Fergus Fall, Minnesota that provides electricity for the customers of Otter Tail Power Company in Minnesota, North Dakota, and South Dakota. While Otter Tail Power was not identified by the MPCA or FLMs as a facility of interest, this facility was identified by the National Parks Conservation Association (NPCA), an advocacy organization that focuses on topics related to the protection of the United States National Park System. The MPCA had met with representatives from the NPCA when they requested to meet and discuss Minnesota's revision to its Regional Haze SIP. During those discussions, the NPCA inquired about the specific list of facilities that the MPCA had requested to prepare a four-factor analysis and why certain facilities had not been included, including Otter Tail Power.

The MPCA determined that the difference was the result of different years of emissions data being used by the NPCA compared to the 2016 emissions rate used by the MPCA. After further review, Otter Tail Power was operating at a lower capacity during 2016, and as a result, the associated emissions were lower than previous and subsequent years. For example, total NO_X and SO_2 emissions in 2016 (332 tons NO_X and 941 tons SO_2) were lower than emissions in 2018 (759 tons NO_X and 2,123 tons SO_2). However, Otter Tail Power also provided notification to the MPCA on June 7, 2021, that the two boilers at the facility had been permanently retired on June 1, 2021, and provided the retired unit exemption notices that they had provided to U.S. EPA for the Acid Rain, CSAPR NO_X Annual, and CSAPT SO_2 Group 2 programs.

The two boilers (Unit #2 Boiler and Unit #3 Boiler) were the primary source of NO_X and SO_2 emissions at Otter Tail Power. Other emission sources included emergency generators and material handling operations. Emissions data reported for 2020 (316 tons NO_X and 749 tons SO_2) shows a decline in NO_X and SO_2 emissions from previous years. With the permanent retirement of the boilers in June 2021, emissions have declined further (draft emissions reported for 2021 are 229 tons NO_X and 495 tons SO_2). Given the permanent retirement of both boilers, and the associated Retired Unit Exemption notices provided to U.S. EPA, the MPCA did not select this source for an analysis of control measures in this implementation period.

Anchor Glass Container Corporation. Anchor Glass Container Corporation owns and operates a glass manufacturing facility located in Shakopee, Minnesota that produces glass containers from raw materials and recycled glass. The primary source of NO_X and SO_2 emissions at the facility are the two glass melting furnaces.

While this facility was identified by the USFS as a facility of interest, the Q/d value for this facility was below a value of four for both the Boundary Waters and Voyageurs Class I areas. A Q/d threshold value of four corresponds to the high priority ranking that was used by the LADCO states to help prioritize sources for gathering control information and potentially requesting a four-factor analysis as discussed previously in this section. This value also corresponds to roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the Q/d analysis for both the Boundary Waters and Voyageurs Class I areas. Given that the Q/d value for this facility was below four, and this facility ranks outside the top 85% of emissions from Minnesota sources in the Q/d analysis, the MPCA decided to not select this source for an analysis of control measures in this implementation period to distribute the analytical work needed for the regional haze program across multiple implementation periods.

Northshore Mining - Babbitt. Northshore Mining - Babbitt is a taconite ore mine with crushing and rail car loading equipment located in Babbitt, Minnesota. The primary emissions from the facility are PM, PM_{10}, and $PM_{2.5}$ that are emitted from the crushing and material handling operations.

While this facility was identified by the USFS as a facility of interest, the Q/d value for this facility was below a value of four for both the Boundary Waters and Voyageurs Class I areas. A Q/d threshold value of four corresponds to the high priority ranking that was used by the LADCO states to help prioritize sources for gathering control information and potentially requesting a four-factor analysis as discussed previously in this section. Minnesota settled on a Q/d threshold value of 4.7 in consultation with FLMs. This value also corresponds to roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the Q/d Analysis for both the Boundary Waters and Voyageurs Class I areas.

Furthermore, as discussed previously in Section 2.3.1, data from the IMPROVE monitoring sites at the Boundary Waters and Voyageurs Class I areas indicates that direct emissions of particulate matter are not large contributors to visibility impairment in these areas. As result, the MPCA did not select this source for an analysis of control measures in this implementation period.

Given that particulate matter emissions are not large contributors to visibility impairment in the Boundary Waters and Voyageurs, the Q/d value for this facility was below four, and this facility ranks outside the top 85% of emissions from Minnesota sources in the Q/d analysis, the MPCA decided to not select this source for an analysis of control measures in this implementation period to distribute the analytical work needed for the regional haze program across multiple implementation periods.

American Crystal Sugar - Moorhead. American Crystal Sugar - Moorhead is a sugar beet processing plant located in Moorhead, Minnesota that produces granulated sugar, powdered sugar, brown sugar, molasses, and pelletized sugar beet pulp. The primary source of NO_X and SO_2 emissions at the facility are the three coal-fired boilers.

While this facility was identified by the USFS as a facility of interest, the Q/d value for this facility was below a value of four for both the Boundary Waters and Voyageurs Class I areas. A Q/d threshold value of four corresponds to the high priority ranking that was used by the LADCO states to help prioritize sources for gathering control information and potentially requesting a four-factor analysis as discussed previously in this section. This value also corresponds to roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the Q/d analysis for both the Boundary Waters and Voyageurs Class I areas. Given that the Q/d value for this facility was below four, and this facility ranks outside the top 85% of emissions from Minnesota sources in the Q/d analysis, the MPCA decided to not select this source for an analysis of control measures in this implementation period to distribute the analytical work needed for the regional haze program across multiple implementation periods.

Duluth Steam Plant 1. Duluth Steam Plant 1 is a district heating system for the City of Duluth, Minnesota. The primary source of NO_X and SO_2 emissions at this facility are the four steam boilers that each burn multiple fuels.

While this facility was identified by the USFS as a facility of interest, the Q/d value for this facility was below a value of four for both the Boundary Waters and Voyageurs Class I areas. A Q/d threshold value of four corresponds to the high priority ranking that was used by the LADCO states to help prioritize sources for gathering control information and potentially requesting a four-factor analysis as discussed previously in this section. This value also corresponds to roughly the top 85% of emissions from Minnesota sources that may impact visibility based on the Q/d analysis for both the Boundary Waters and Voyageurs Class I areas. Given that the Q/d value for this facility was below four, and this facility ranks outside the top 85% of emissions from Minnesota sources in the Q/d analysis, the MPCA decided to not select this source for an analysis of control measures in this implementation period to distribute the analytical work needed for the regional haze program across multiple implementation periods.

2.4. Step 4 - Characterization of factors for emission control measures

The Regional Haze Rule requires states to identify potential emission control measures for the selected sources and identify what factors are considered in determining what measures are necessary to make reasonable progress.[113] All states, including those without Class I areas, are required to select sources for analysis and determine what emission controls measures are necessary to make reasonable progress at the state's own Class I areas and Class I areas in other states.[114]

U.S. EPA has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 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. … In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.*[115]

As well as reiterating that states are required to consider the four factors identified in 40 CFR § 51.308(f)(2)(i), U.S. EPA provides additional information in its August 2019 Guidance that states may

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[113] See *40 CFR § 51.308(f)(2)(i).*
[114] *See id.*
[115] *See id.*

consider in determining what measures are needed to make reasonable progress and in the analysis of emission control measures. The examples U.S. EPA provides includes the visibility benefit of a potential emission reduction measure and one or more of the five additional factors listed in 40 CFR § 51.308(f)(2)(iv).

Additionally, the Regional Haze Rule requires that the SIP document how a state has done its analysis in 40 CFR § 51.308(f)(2)(i) and 40 CFR § 51.308(f)(2)(iii).

> *The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.*[116]
>
> *The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects. The State may meet this requirement by relying on technical analyses developed by a regional planning process and approved by all State participants.*[117]

Additional detail regarding how the MPCA identified potential control measures and what factors were considered in the analysis of emission control measures is provided in the following sections.

2.4.1. Emission control measures considered

As discussed previously, the MPCA sent RFI letters to 17 facilities requesting that they prepare and submit a four-factor analysis for the identified emission units that examined potential control measures to reduce emissions of the identified pollutant(s). The MPCA did not specify which control measures should be considered, instead referencing that the analyses should follow the recommendations identified in U.S. EPA's August 2019 Guidance.[118]

The MPCA received these analyses from facilities for emission units that had not provided additional information to support an effective controls determination, to identify a planned retirement date, or were otherwise removed from the source selection process as discussed in Section 2.3. Between July 2020 and January 2022, the MPCA reviewed the submitted analyses and consulted with FLMs, Tribes, and other states regarding consistency and criteria/thresholds used in assessing potential emission reduction strategies. During this time period, the MPCA provided facilities with comments prepared by MPCA staff as well as comments prepared by the FLMs from the U.S. FS and U.S. NPS. Generally, these comments focused on which NO_X and SO_2 control technologies were considered, the expected reduction of those technologies, and specific details of the four-factor analyses such as information used in cost estimate portion.

As discussed previously, the sources that were requested to provide a four-factor analysis were taconite processing facilities, pulp/paper mills, sugar manufacturing facilities, and electric power generation facilities. The emission units identified at these facilities were fuel combustion sources (generally boilers or furnaces), so the emission control measures considered were similar across sources and focused on combustion controls and post-combustion controls. Regarding NO_X controls, the emission control measures considered generally included:

- Low NO_X burners and/or over-fire air systems

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[116] *See id.*
[117] 40 CFR § 51.308(f)(2)(iii).
[118] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra,* at 28-36.

- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)

Regarding SO_2 controls, the emission control measures considered generally included:

- Wet flue gas desulfurization (FGD) or wet scrubbing
- Dry FGD or dry scrubbing
- Dry sorbent injection (DSI)

Overall, each source provided an analysis of control measures specific to the emission units identified by the MPCA. Table 44 below summarizes the control measures considered for the facilities and emission units that the MPCA requested to conduct a four-factor analysis. The MPCA also considered lower permit limits for NO_X and SO_2 that could achieve same or better emission reductions if facilities indicated interest in that option.

Table 44. Control measures considered in the four-factor analysis

Facility name	Emission unit	Pollutant	Control measure(s) considered
American Crystal Sugar - Crookston	Boiler 1	NO_X	SNCR, SCR
		SO_2	DSI, Dry FGD
	Boiler 2	NO_X	SNCR, SCR
		SO_2	DSI, Dry FGD
	Boiler 3	NO_X	SNCR, SCR
		SO_2	DSI, Dry FGD
American Crystal Sugar - East Grand Forks	Boiler 1	NO_X	SNCR, SCR
		SO_2	DSI, Dry FGD
	Boiler 2	NO_X	SNCR, SCR
		SO_2	DSI, Dry FGD
Boise White Paper	Recovery Furnace	NO_X	N/A (effectively controlled)
	Boiler 1	NO_X	LNB w/ FGR & OFA, SCR
	Boiler 2	NO_X, SO_2	N/A (effectively controlled)
Cleveland Cliffs Minorca Mine Inc.	Indurating Machine	NO_X, SO_2	N/A (effectively controlled)
Hibbing Public Utilities Commission	Boiler No. 1A	NO_X	SNCR, SCR
		SO_2	Spray Dry Scrubber, Wet Scrubber
	Boiler No. 2A	NO_X	SNCR, SCR
		SO_2	Spray Dry Scrubber, Wet Scrubber
	Boiler No. 3A	NO_X	SNCR, SCR
		SO_2	Spray Dry Scrubber, Wet Scrubber
	Wood Fired Boiler	NO_X	SCR
Hibbing Taconite Company	Indurating Furnace Line 1	NO_X, SO_2	N/A (effectively controlled)
	Indurating Furnace Line 2	NO_X, SO_2	
	Indurating Furnace Line 3	NO_X, SO_2	
Minnesota Power - Boswell Energy Center	Unit 1	NO_X, SO_2	N/A (unit retirement)
	Unit 2	NO_X, SO_2	
	Unit 3	NO_X, SO_2	N/A (effectively controlled)
	Unit 4	NO_X, SO_2	

Facility name	Emission unit	Pollutant	Control measure(s) considered
Minnesota Power - Taconite Harbor Energy	Boiler 1	NO_X, SO_2	N/A (unit retirement)
	Boiler 2	NO_X, SO_2	
Northshore Mining - Silver Bay	Power Boiler 1	NO_X	SNCR, SCR
		SO_2	DSI, Spray Dry Absorber
	Power Boiler 2	NO_X	LNB w/ OFA, SNCR, SCR
		SO_2	DSI, Spray Dry Absorber
	Furnace 11	NO_X, SO_2	N/A (effectively controlled)
	Furnace 12	NO_X, SO_2	
Sappi Cloquet LLC	Power Boiler #9	NO_X	SNCR, SCR
		SO_2	DSI, Spray Dry Absorber
	Recovery Boiler #10	NO_X	N/A (effectively controlled)
Southern Minnesota Beet Sugar Coop	Boiler 1	NO_X	LNB w/ OFA, SNCR, SCR
		SO_2	DSI, Spray Dry Absorber
United Taconite LLC - Fairlane Plant	Line 1 Pellet Induration	NO_X, SO_2	N/A (effectively controlled)
	Line 2 Pellet Induration	NO_X, SO_2	
US Steel Corporation - Keetac	Grate Kiln	NO_X, SO_2	N/A (effectively controlled)
US Steel Corporation - Minntac	Line 3 Rotary Kiln	NO_X, SO_2	N/A (effectively controlled)
	Line 4 Rotary Kiln	NO_X, SO_2	
	Line 5 Rotary Kiln	NO_X, SO_2	
	Line 6 Rotary Kiln	NO_X, SO_2	
	Line 7 Rotary Kiln	NO_X, SO_2	
Virginia Department of Public Utilities	Boiler 7	NO_X	SNCR, SCR
		SO_2	Spray Dry Scrubber, Wet Scrubber
	Boiler 9	NO_X, SO_2	N/A (unit retirement)
	Boiler 11	NO_X	SCR
Xcel Energy - Allen S. King	Boiler 1	NO_X, SO_2	N/A (unit retirement)
Xcel Energy - Sherburne	Unit 1	NO_X, SO_2	N/A (unit retirement)
	Unit 2	NO_X, SO_2	
	Unit 3	NO_X, SO_2	

Additional detail regarding the control measures considered, for the emission units that were not removed from further analysis, is provided in the following sections. For information regarding emission units that were removed from further analysis, see Section 2.3.3 for those that were removed due to consideration of their remaining useful life and Section 2.3.5 for those that were removed due to an effectively controlled determination.

2.4.2. Emissions information for characterizing emissions-related factors

To evaluate the control measures considered for any emission unit, emission information is required to estimate the reduction from those potential control measures. Specifically, information on emissions reductions is tied to the cost of compliance measure. U.S. EPA provides recommendations in its August 2019 Guidance on the selection of emission data for use in the control measure analysis and estimating the emission reductions from potential control measures. U.S. EPA's recommendations generally reiterate the requirement to document emissions information as required by 40 CFR 51.308(f)(2)(iii) and provide suggestions on the use of actual emission versus allowable emissions and the choice of emissions inventory year.[119]

In the four-factor analysis request to facilities, the MPCA did not specify what year or choice of emissions should be considered, instead referencing that the analyses should follow the recommendations identified in U.S. EPA's August 2019 Guidance. In further discussions with these facilities the MPCA highlighted the use of the LADCO emissions inventory data, as discussed previously in Section 2.3.2, in the surrogate visibility analysis to select sources for an analysis of control measures. The MPCA indicated to facilities that the LADCO data (i.e., actual emissions reported in 2016) would be a good starting point for facilities to prepare a four-factor analysis, but the MPCA conveyed that facilities could provide different emissions data if they thought 2028 operations would be significantly different than 2016 operations. The MPCA also conveyed that emissions should be based on representative historical operations and follow the identified recommendations regarding emissions data in U.S. EPA's August 2019 Guidance discussed above.[120]

In general, facilities provided emissions data that was reported to the most recent Minnesota annual emission inventory (typically 2018 or 2019), which was at least as recent as the emissions data submitted to U.S. EPA's 2017 National Emission Inventory (NEI), at the time the requested four-factor analyses were provided to MPCA. Source-specific emissions data used by facilities in the four-factor analyses is available in Appendix B. Four-Factor Analyses - Facility Responses.

The MPCA reviewed the emissions data provided in each four-factor analysis and compared that information to the emissions data reported to Minnesota's annual emission inventory for the years 2016 through 2020. MPCA compared the emissions data to these years of reported emissions data to verify that the emissions used in the four-factor analysis were reasonably grounded in historical reported emissions. Where emissions data used by facilities did not match the baseline emissions as calculated in the Control Cost Manual cost estimation spreadsheets, the MPCA revised the emissions data used as part of evaluating potential control measures (U.S. EPA's Control Cost Manual and cost estimation spreadsheets are described in further detail in Section 2.4.3).[121] The versions of the four-factor analyses with revisions to the cost estimates made by the MPCA, including the revised emissions information discussed, are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions.

The "4-Factor Analysis" column of NO_X and SO_2 emissions data provided in the following tables is displays the revised emissions data used by the MPCA. The emission values do not necessarily exactly match a particular reporting year due to differences in how each facility prepared their four-factor analysis (e.g., using the higher emission rate for two identical boilers as a conservative estimate of emissions from both) or rounding of values as within Minnesota's annual emission inventory database.

Specifically, regarding American Crystal Sugar - Crookston the facility reports annual NO_X emissions based on a pound per hour value determined during stack testing while the four-factor analysis calculated emissions based on lb/MMBtu value. MPCA and the facility reviewed the stack testing results and suspect that the calculated pound per hour values are skewed high so have instead used the lb/MMBtu value for the four-factor analysis.

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[119] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra,* at 17-18.
[120] *See id.*
[121] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS, *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution* (last visited June 23, 2022) [hereinafter COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS].

Table 45 below summarizes the NO_X emissions data, as reported to Minnesota's annual emissions inventory and used in the four-factor analysis, for the facilities and emission units that continued through the control measure analysis.

Table 45. Four-factor analysis NO_X Emissions Data

Facility name	Emission unit	NO_X emissions data (tons)					
		2016	2017	2018	2019	2020	4-Factor Analysis
American Crystal Sugar - Crookston	Boiler 1	183.02	210.61	216.01	201.52	121.40	115.01
	Boiler 2	198.72	227.21	231.31	216.52	125.10	115.01
	Boiler 3	257.82	215.61	214.01	201.52	154.81	134.32
American Crystal Sugar - East Grand Forks	Boiler 1	337.20	337.20	358.50	354.00	279.20	338.10
	Boiler 2	298.40	298.40	343.80	325.80	268.40	338.10
Boise White Paper	Boiler 1	72.87	67.07	46.13	90.92	46.81	94.53
Hibbing Public Utilities Commission	Boiler No. 1A	157.81	118.87	111.75	43.21	23.65	111.75
	Boiler No. 2A	39.50	1.09	0.00	0.00	0.00	111.75
	Boiler No. 3A	193.60	167.14	133.27	82.20	81.70	133.27
	Wood Fired Boiler	87.05	86.76	31.95	15.24	10.67	31.95
Northshore Mining - Silver Bay	Power Boiler 1	269.11	375.57	666.65	277.09	-	666.63
	Power Boiler 2	818.50	1,008.00	395.90	404.10	-	1,008.11
Sappi Cloquet LLC	Power Boiler #9	433.60	377.50	376.60	346.80	340.00	347.05
Southern Minnesota Beet Sugar Coop	Boiler 1	929.60	909.00	899.70	780.30	939.20	908.96
Virginia Department of Public Utilities	Boiler 7	23.11	49.25	59.64	70.76	51.66	70.79
	Boiler 11	103.45	82.94	42.03	38.05	74.90	103.44

Table 46 below summarizes the SO_2 emissions data, as reported to Minnesota's annual emissions inventory and used in the four-factor analysis, for the facilities and emission units that continued through the control measure analysis.

Table 46. Four-factor analysis SO_2 Emissions Data

Facility name	Emission unit	SO_2 emissions data (tons)					
		2016	2017	2018	2019	2020	4-Factor Analysis
American Crystal Sugar - Crookston	Boiler 1	322.69	242.15	248.24	231.67	187.70	241.00
	Boiler 2	299.09	262.05	266.74	249.67	175.20	241.00
	Boiler 3	253.49	270.65	268.65	253.00	229.16	253.00
American Crystal Sugar - East Grand Forks	Boiler 1	383.90	383.90	425.40	454.40	271.80	452.32
	Boiler 2	357.40	357.40	426.30	449.40	277.90	452.32
Hibbing Public Utilities Commission	Boiler No. 1A	149.10	181.70	83.08	3.29	3.25	108.73
	Boiler No. 2A	37.33	1.23	-	-	-	108.73
	Boiler No. 3A	168.32	158.04	78.65	36.18	36.18	104.93
Northshore Mining - Silver Bay	Power Boiler 1	297.93	607.40	1,046.14	456.96	-	1,046.14
	Power Boiler 2	537.60	780.30	396.60	240.50	-	780.30

Facility name	Emission unit	SO_2 emissions data (tons)					
		2016	2017	2018	2019	2020	4-Factor Analysis
Sappi Cloquet LLC	Power Boiler #9	49.58	80.00	17.12	21.77	366.50	22.02
Southern Minnesota Beet Sugar Coop	Boiler 1	805.40	795.00	701.90	587.40	852.30	794.97
Virginia Department of Public Utilities	Boiler 7	39.05	68.39	77.25	92.94	73.53	66.19

The MPCA also compared the emissions data used in the four-factor analyses to the reported emissions data in Minnesota's annual emissions inventory and the emissions data included in the regional scale modeling. The emissions inventory years used for comparison are 2016 and 2017 as those were the years used in the source selection step, discussed previously in Section 2.3.2, with revisions made specifically for Northshore Mining - Silver Bay to account for the two Power Boilers operating at reduced capacity in 2016. Table 47 provides this comparison for NO_X emissions data for the hybrid of 2016/2017 emissions data, the emissions data modeled for 2016 and 2028, and the emissions data used in the four-factor analysis.

Table 47. Comparison of emissions inventory, modeling, and four-factor analysis NO_X emissions data

Facility name	Emission unit	NO_X emissions data (tons)			
		2016	2016 Model	2028 Model	4-Factor Analysis
American Crystal Sugar - Crookston	Boiler 1	183.02	183.52	179.05	115.01
	Boiler 2	198.72	199.26	194.41	115.01
	Boiler 3	257.82	258.53	252.22	134.32
American Crystal Sugar - East Grand Forks	Boiler 1	337.20	338.12	329.88	338.10
	Boiler 2	298.40	299.22	291.92	338.10
Boise White Paper	Boiler 1	72.87	73.07	81.60	94.53
Hibbing Public Utilities Commission	Boiler No. 1A	157.81	158.23	164.51	111.75
	Boiler No. 2A	39.50	39.61	164.52	111.75
	Boiler No. 3A	193.60	194.12	164.51	133.27
	Wood Fired Boiler	87.05	87.29	87.29	31.95
Northshore Mining - Silver Bay[122]	Power Boiler 1	375.57	376.60	0.00	666.63
	Power Boiler 2	1,008.00	1,010.76	0.00	1,008.11
Sappi Cloquet LLC	Power Boiler #9	433.60	434.79	475.17	347.05
Southern Minnesota Beet Sugar Coop	Boiler 1	929.60	932.15	909.42	908.96
Virginia Department of Public Utilities	Boiler 7	23.11	23.17	0.00	70.79
	Boiler 11	103.45	103.74	103.74	103.44

Table 48 provides this comparison for SO_2 emissions data for the f 2016 emissions data, the emissions data modeled for 2016 and 2028, and the emissions data used in the four-factor analysis.

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[122] NO_X emissions data shown in the "2016" column for Northshore Mining - Silver Bay is from 2017 due to the two boilers operating at reduced capacity in 2016.

Table 48. Comparison of emissions inventory, modeling, and four-factor analysis SO_2 emissions data

Facility Name	Emission Unit	SO_2 Emissions Data (tons)			
		2016	2016 Model	2028 Model	4-Factor Analysis
American Crystal Sugar - Crookston	Boiler 1	322.69	323.57	315.71	241.00
	Boiler 2	299.09	299.91	292.62	241.00
	Boiler 3	253.49	254.18	248.01	253.00
American Crystal Sugar - East Grand Forks	Boiler 1	383.90	384.95	375.57	452.32
	Boiler 2	357.40	358.38	349.64	452.32
Hibbing Public Utilities Commission	Boiler No. 1A	149.10	149.51	347.97	108.73
	Boiler No. 2A	37.33	37.43	347.97	108.73
	Boiler No. 3A	168.32	168.78	347.97	104.93
Northshore Mining - Silver Bay[123]	Power Boiler 1	607.40	609.06	0.00	1,046.14
	Power Boiler 2	780.30	782.44	0.00	780.30
Sappi Cloquet LLC	Power Boiler #9	49.58	49.72	54.33	22.02
Southern Minnesota Beet Sugar Coop	Boiler 1	805.40	807.61	787.91	794.97
Virginia Department of Public Utilities	Boiler 7	39.05	39.16	0.00	66.19

Additional emission unit specific information utilized in the four-factor analyses, including permitted NO_X and SO_2 emission rates, actual NO_X and SO_2 emission rates, and the design heat input capacity of the emission units is provided in Table 49 below.

Table 49. Emission unit specific factors

Facility name	Emission unit	Max heat input (MMBtu/hr)	Permitted emission rate (lb/MMBtu)[124]		Actual emission rate (lb/MMBtu)	
			NO_X	SO_2	NO_X	SO_2
American Crystal Sugar - Crookston	Boiler 1	137	0.73	0.93	0.33	0.37
	Boiler 2	137	0.73	0.93	0.33	0.37
	Boiler 3	165	0.73	0.93	0.32	0.41
American Crystal Sugar - East Grand Forks	Boiler 1	356	0.64	1.10	0.34	0.45
	Boiler 2	356	0.64	1.10	0.34	0.45
Boise White Paper	Boiler 1	398	0.20	-	0.131	0.001
Hibbing Public Utilities Commission	Boiler No. 1A	216	-	0.90	0.33	0.30
	Boiler No. 2A	216	-	0.90	0.33	0.30
	Boiler No. 3A	248	-	0.90	0.39	0.27

[123] *SO_2 emissions data shown in the "2016" column for Northshore Mining - Silver Bay is from 2017 due to the two boilers operating at reduced capacity in 2016.*

[124] *Permitted emission rates displayed in this table are either listed directly in the associated permit as a lb/MMbtu value or have been translated from a lb/hr emission limit to a lb/MMBtu rate (e.g., Boiler 1 at American Crystal Sugar - East Grand Forks is limited to 391.8 lb SO_2/hr which corresponds to 1.10 lb SO_2/MMbtu at the max heat input of 356 MMBtu/hr). See* MPCA, *Air Permits Issued in Minnesota*, https://www.pca.state.mn.us/air/air-permits-issued-minnesota (last visited June 6, 2022) (location of current versions of each permit that identify the listed emission rate).

Facility name	Emission unit	Max heat input (MMBtu/hr)	Permitted emission rate (lb/MMBtu)[124]		Actual emission rate (lb/MMBtu)	
			NO_X	SO_2	NO_X	SO_2
	Wood Fired Boiler	230	0.15	-	0.13	0.03
Northshore Mining - Silver Bay	Power Boiler 1	517	-	1.5	0.35	0.61
	Power Boiler 2	765	-	1.5	0.58	0.46
Sappi Cloquet LLC	Power Boiler #9	430	0.70	0.06	0.292	0.02
Southern Minnesota Beet Sugar Coop	Boiler 1	472.4	0.70	1.20	0.59	0.52
Virginia Department of Public Utilities	Boiler 7	175	-	0.813	0.34	0.50
	Boiler 11	230	0.15	-	0.15	0.03

Additional discussion on emissions information is also provided in Sections 2.6. Regional scale modeling, 2.8.5. Emissions inventory, and Section 2.10.4. Emissions progress. Additional detail regarding the four statutory factors is provided in the following sections.

2.4.3. Cost of compliance (statutory factor 1)

To evaluate the cost of compliance, the MPCA requested that each facility prepare cost estimates for the potential control measures evaluated in the four-factor analysis. U.S. EPA provides recommendations in its August 2019 Guidance on determining the costs of identified control measures.[125] U.S. EPA's recommendations generally suggest that states follow the methodologies and recommendations in the U.S. EPA Air Pollution Control Cost Manual and use the cost calculation spreadsheets where available for the type of emission control system.[126] U.S. EPA also points to the use of these resources as a way to compare different control options for the same source and comparisons across different sources. This also provides consistency for informed public comment and decision-making while allowing states to rely on a simple reference to the Control Cost Manual as documentation of, and rationale for, the approach.

In the four-factor analysis request to facilities, and in subsequent conversations, the MPCA recommended that facilities prepare cost estimates by following the recommendations identified in U.S. EPA's August 2019 Guidance and use the cost estimation spreadsheets where available for the type of control measure.[127] In general, facilities provided cost estimates that followed the recommendations in the Control Cost Manual and used the cost estimation spreadsheets when available. The MPCA reviewed the cost estimates that facilities provided, including the comments provided by FLMs, U.S. EPA, or Tribes, and revised the cost estimates prepared to address certain parameters in those estimates (e.g., interest rate, retrofit factors, etc.). Regarding interest rates, this parameter generally fluctuates over time and is influenced by the current bank prime interest rate. As interest rates change, the costs determined in a cost estimate that used an interest rate tied to the current bank prime interest rate would change as well. Normal fluctuations in this parameter is not expected to affect the determination of whether the control is cost effective or not.

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[125] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 31-32.
[126] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*
[127] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 31-32; U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*

U.S. EPA also recommends that states express the cost of compliance in terms of a cost per ton of emissions reduced by the control measure.[128] The following tables provide a summary of the cost of compliance for the NO_X and SO_2 technologies evaluated by facilities that continued through the control measure analysis. Table 50 provides the summary of NO_X control measures and associated costs as prepared by the identified facilities.

Table 50. NO_X control information (facility provided)

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
American Crystal Sugar - Crookston	Boiler 1	SNCR	28	$3,774,769	$332,596	$11,929
		SCR	91	$14,757,119	$1,328,167	$14,657
	Boiler 2	SNCR	28	$3,774,769	$332,596	$11,929
		SCR	91	$14,757,119	$1,328,167	$14,657
	Boiler 3	SNCR	13	$3,844,323	$340,902	$25,379
		SCR	109	$16,766,382	$1,504,442	$13,785
American Crystal Sugar - East Grand Forks	Boiler 1	SNCR	29	$5,401,600	$491,728	$17,009
		SCR	245	$28,827,447	$2,620,761	$10,697
	Boiler 2	SNCR	29	$5,401,600	$491,728	$17,009
		SCR	245	$28,827,447	$2,620,761	$10,697
Boise White Paper	Boiler 1	LNB/OFA + FGR	56	$11,144,531	$1,557,544	$27,712
		SCR	63	$7,828,245	$970,836	$15,375
Hibbing Public Utilities Commission	Boiler 1	SNCR	43	$474,810	$305,076	$7,067
		SCR	92	$5,507,541	$1,104,940	$12,044
	Boiler 2	SNCR	43	$474,810	$305,076	$7,067
		SCR	92	$5,507,541	$1,104,940	$12,044
	Boiler 3	SNCR	58	$570,839	$366,777	$6,365
		SCR	122	$6,323,473	$1,268,635	$10,361
	Wood Fired Boiler	SCR	41	$2,345,805	$611,371	$15,015
Northshore Mining - Silver Bay	Power Boiler 1	SNCR	-	$7,239,275	$992,019	-
		SCR	-	$40,647,490	$4,159,366	-
	Power Boiler 2	SNCR	-	$8,917,925	$1,435,176	-
		LNB+OFA	-	$11,609,362	$1,725,870	-
		SCNR+LNB+OFA	-	$20,527,287	$3,161,046	-
		SCR	-	$55,724,684	$5,985,367	-
		SCR+LNB+OFA	-	$67,334,046	$7,711,237	-
Sappi Cloquet	Boiler 9	SNCR	87	$6,068,270	$826,547	$9,527
		SCR	278	$29,195,285	$2,640,026	$9,509
Southern Minnesota Beet Sugar Coop	Boiler 1	LNB	106	$2,057,668	$546,852	$5,154
		LNB+OFA	230	$3,560,926	$825,735	$3,585
		SNCR	340	$6,908,987	$1,297,449	$3,815

[128] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 21.

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
		SCR	813	$38,983,220	$5,709,678	$7,027
Virginia Department of Public Utilities	Boiler 7	SNCR	20	$227,686	$146,294	$7,215
		SCR	43	$4,622,231	$927,326	$21,522
	Boiler 11	SCR	42	$2,429,973	$633,307	$15,053

Table 51 provides the summary of NO_X control measures and associated costs as revised by the MPCA. Revisions generally included adjustments to the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates. The versions of the four-factor analyses with revisions to the cost estimates made by the MPCA, including the revised parameter information discussed, are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions.

Table 51. NO_X control information (MPCA revision)

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
American Crystal Sugar - Crookston	Boiler 1	SNCR	28	$3,774,769	$349,565	$12,537
		SCR	91	$14,757,119	$1,199,421	$13,236
	Boiler 2	SNCR	28	$3,774,769	$349,565	$12,537
		SCR	91	$14,757,119	$1,199,421	$13,236
	Boiler 3	SNCR	13	$3,844,323	$359,817	$26,787
		SCR	109	$16,766,382	$1,359,046	$12,453
American Crystal Sugar - East Grand Forks	Boiler 1	SNCR	35	$5,417,537	$540,063	$15,366
		SCR	269	$28,837,241	$2,393,757	$8,906
	Boiler 2	SNCR	35	$5,417,537	$540,063	$15,366
		SCR	269	$28,837,241	$2,393,757	$8,906
Boise White Paper	Boiler 1	LNB/OFA + FGR	58	$11,144,531	$1,557,544	$26,649
		SCR	66	$8,031,851	$905,022	$13,783
Hibbing Public Utilities Commission	Boiler 1	SNCR	45	$3,143,455	$294,673	$6,592
		SCR	95	$13,230,252	$940,248	$9,898
	Boiler 2	SNCR	45	$3,143,455	$294,673	$6,592
		SCR	95	$13,230,252	$940,248	$9,898
	Boiler 3	SNCR	53	$3,383,762	$320,080	$6,004
		SCR	113	$14,684,586	$1,042,058	$9,198
	Wood Fired Boiler	SCR	25	$13,936,042	$953,462	$38,262
Northshore Mining - Silver Bay	Power Boiler 1	SNCR	167	$5,929,287	$819,324	$4,916
		SCR	533	$33,130,713	$2,792,174	$5,236
	Power Boiler 2	SNCR	252	$7,262,749	$1,015,960	$4,031
		LNB+OFA	403	$11,609,362	$1,555,019	$3,856
		SCNR+LNB+OFA	554	$18,872,111	$2,570,979	$4,637
		SCR	806	$45,313,042	$3,813,166	$4,728
		SCR+LNB+OFA	887	$56,922,404	$5,368,185	$6,051
Sappi Cloquet	Boiler 9	SNCR	87	$6,068,270	$742,887	$8,562

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
		SCR	278	$29,945,905	$2,337,020	$8,417
Southern Minnesota Beet Sugar Coop	Boiler 1	LNB	215	$2,057,668	$483,600	$2,245
		LNB+OFA	323	$3,560,926	$732,452	$2,266
		SNCR	447	$7,159,267	$1,314,072	$2,942
		SCR	832	$39,367,889	$4,979,779	$5,986
Virginia Department of Public Utilities	Boiler 7	SNCR	28	$2,961,727	$269,972	$9,534
		SCR	60	$12,033,247	$832,990	$13,843
	Boiler 11	SCR	81	$14,011,921	$1,026,726	$12,724

Table 52 provides the summary of SO_2 control measures and associated costs as prepared by the identified facilities.

Table 52. SO_2 control information (facility provided)

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
American Crystal Sugar - Crookston	Boiler 1	DSI	169	$12,069,333	$2,357,100	$13,972
		Dry FGD	205	$15,388,300	$3,463,600	$16,908
	Boiler 2	DSI	169	$12,069,333	$2,357,100	$13,972
		Dry FGD	205	$15,388,300	$3,463,600	$16,908
	Boiler 3	DSI	177	$12,069,333	$2,357,100	$13,309
		Dry FGD	215	$17,192,000	$3,809,500	$17,714
American Crystal Sugar - East Grand Forks	Boiler 1	DSI	317	$18,314,200	$3,773,250	$11,917
		Dry FGD	384	$27,199,600	$5,646,800	$14,687
	Boiler 2	DSI	317	$18,314,200	$3,773,250	$11,917
		Dry FGD	384	$27,199,600	$5,646,800	$14,687
Hibbing Public Utilities Commission	Boiler 1A	Dry Scrubber	87	$17,689,685	$12,749,611	$146,345
		Wet Scrubber	98	$22,931,073	$5,562,095	$56,750
	Boiler 2A	Dry Scrubber	87	$17,689,685	$12,749,611	$146,345
		Wet Scrubber	98	$22,931,073	$5,562,095	$56,750
	Boiler 3A	Dry Scrubber	88	$21,267,374	$15,328,184	$173,742
		Wet Scrubber	99	$27,568,818	$6,687,014	$67,374
Northshore Mining - Silver Bay	Power Boiler 1	DSI	-	$34,463,571	$6,144,640	-
		Spray Dry Absorber	-	$58,737,702	$12,796,563	-
	Power Boiler 2	DSI	-	$37,737,598	$6,943,044	-
		Spray Dry Absorber	-	$61,962,015	$13,572,909	-
Sappi Cloquet	Boiler 9	DSI	11	$41,178,526	$5,672,396	$515,275
		Spray Dry Absorber	15	$144,535,337	$24,484,747	$1,588,695
	Boiler 1	DSI	550	$37,755,277	$7,040,200	$12,799

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Southern Minnesota Beet Sugar Coop		Spray Dry Absorber	707	$54,520,933	$8,035,215	$11,362
Virginia Department of Public Utilities	Boiler 7	Dry Scrubber	56	$8,483,162	$6,114,129	$110,109
		Wet Scrubber	62	$10,996,692	$2,667,326	$42,698

Table 53 provides the summary of SO_2 control measures and associated costs as revised by the MPCA. Revisions generally included adjustments to the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates. The versions of the four-factor analyses with revisions to the cost estimates made by the MPCA, including the revised parameter information discussed, are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions.

Table 53. SO_2 control information (MPCA revision)

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
American Crystal Sugar - Crookston	Boiler 1	DSI	169	$12,069,333	$2,216,133	$13,137
		Dry FGD	205	$15,388,300	$3,308,100	$16,149
	Boiler 2	DSI	169	$12,069,333	$2,216,133	$13,137
		Dry FGD	205	$15,388,300	$3,308,100	$16,149
	Boiler 3	DSI	177	$12,069,333	$2,216,133	$12,513
		Dry FGD	215	$17,192,000	$3,635,800	$16,907
American Crystal Sugar - East Grand Forks	Boiler 1	DSI	317	$18,314,200	$3,559,350	$11,241
		Dry FGD	384	$27,199,600	$5,378,000	$13,988
	Boiler 2	DSI	317	$18,314,200	$3,559,350	$11,241
		Dry FGD	384	$27,199,600	$5,378,000	$13,988
Hibbing Public Utilities Commission	Boiler 1A	Dry Scrubber	87	$22,734,042	$1,835,937	$21,106
		Wet Scrubber	98	$38,565,895	$3,181,703	$32,512
	Boiler 2A	Dry Scrubber	87	$22,734,042	$1,835,937	$21,106
		Wet Scrubber	98	$38,565,895	$3,181,703	$32,512
	Boiler 3A	Dry Scrubber	84	$25,329,758	$2,022,942	$24,100
		Wet Scrubber	94	$41,194,869	$3,359,413	$35,574
Northshore Mining - Silver Bay	Power Boiler 1	DSI	732	$28,001,651	$4,946,246	$6,754
		Spray Dry Absorber	942	$58,737,702	$9,618,924	$10,216
	Power Boiler 2	DSI	546	$30,661,798	$5,628,525	$10,305
		Spray Dry Absorber	702	$61,962,015	$10,221,871	$14,555
Sappi Cloquet	Boiler 9	DSI	11	$41,178,526	$5,672,396	$515,275
		Spray Dry Absorber	15	$144,535,337	$24,484,747	$1,588,695
Southern Minnesota Beet Sugar Coop	Boiler 1	DSI	556	$37,755,277	$6,285,702	$11,296
		Spray Dry Absorber	715	$54,520,933	$7,224,301	$10,097

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Virginia Department of Public Utilities	Boiler 7	Dry Scrubber	53	$17,430,191	$1,346,125	$25,420
		Wet Scrubber	60	$32,985,530	$2,558,065	$42,939

The cost estimates prepared by facilities are available in Appendix B. Four-Factor Analyses - Facility Responses. The versions of the four-factor analyses with revisions to the cost estimates made by the MPCA, including the revisions to parameters such as interest rate and retrofit factors discussed, are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions.

2.4.4. Time necessary for compliance (statutory factor 2)

Characterizing the time necessary for compliance involves estimating the time needed for a source to comply with a potential control measure. U.S. EPA provides recommendations in its August 2019 Guidance that states should consider source-specific factors when available and justify the time needed to install a control measure as being reasonable.[129] In contrast to BART requirements in the first implementation period, U.S. EPA notes that there is no requirement in the Regional Haze Rule that control measures, which were determined to be necessary to make reasonable progress, be installed as expeditiously as practicable or within five years of U.S. EPA's approval of a state's Regional Haze SIP.[130]

In the four-factor analysis request to facilities, and in subsequent conversations, the MPCA recommended that facilities prepare the analyses by following the recommendations identified in U.S. EPA's August 2019 Guidance. In general, facilities provided their estimate of the time needed to install the evaluated control technologies, considering the time needed for design, engineering, procurement, and installation. The MPCA reviewed the time needed for compliance with potential control measures provided by facilities to consider what compliance timeframe would be reasonable for each specific source. Source-specific considerations for the time needed for compliance used in the four-factor analyses provided by facilities are available in Appendix B. Four-Factor Analyses - Facility Responses.

In conversations with facilities, the MPCA reiterated the concepts provided in U.S. EPA's August 2019 Guidance, indicating the inherent flexibility in setting a compliance schedule, and set a default compliance deadline of 2028 for any controls that were determined to be necessary to make reasonable progress. The impact of any potential control measures installed by 2028 would be realized prior to the beginning of the third implementation period. The MPCA clarified that the MPCA would work with facilities where controls were determined to be necessary to make reasonable progress to incorporate source-specific installation schedules. The MPCA believes this is a reasonable approach to use 2028 as a default compliance deadline, allowing for source-specific considerations, given that the second implementation period ends in 2028 as well. Compliance deadlines for control measures that were determined to be necessary to continue making reasonable progress are discussed later in Section 2.5.6.

2.4.5. Energy and non-air environmental impacts (statutory factor 3)

Characterizing the energy and non-air environmental impacts generally includes an assessment of the impacts of a potential control measure on energy consumption and to other environmental media. Impacts to other media can include waste generation and disposal necessary, transportation impacts,

[129] *See U.S. EPA, Aug. 2019 EPA Guidance, supra, at 32-33.*
[130] *See id.*

increased water consumption and water quality impacts, among other source-specific impacts identified.

In its August 2019 Guidance, U.S. EPA identifies that the Control Cost Manual provides recommendations on estimating the energy-related impacts and recommended that states focus on the direct energy consumption at the source.[131] In general, facilities provided cost estimates that followed the recommendations in the Control Cost Manual, using the cost estimation spreadsheets when available, which accounts for the electricity consumed by a control technology.[132] Facilities also identified other non-air environmental impacts specific to the emission unit(s) and associated control measures evaluated.

In general, the NO_X and SO_2 combustion modifications and post-combustion controls considered across the sources evaluated can have the following impacts:

- Energy use, positively or negatively, through the associated efficiency impacts of modifications (e.g., boiler tuning, reduced thermal efficiency as air-to-fuel ratio increases and temperature decreases, etc.) and technologies that increase energy use (e.g., additional fans/compressors needed for control systems).
- Solid, liquid, or hazardous waste generation and disposal (e.g., particulate matter collected by a dry FGD system, wastewater and sludge generated by a wet FGD system, etc.).
- Use of reagents (e.g., urea or ammonia) can contaminant fly ash making it unsuitable for sale.
- Additional systems needed for some technologies and their associated impacts (e.g., a flue gas reheater may be needed and increases energy use).

Source-specific energy and non-air environmental impacts are identified in the information provided by the facilities that MPCA requested prepare and submit a four-factor analysis, see Appendix B. Four-Factor Analyses - Facility Responses.

2.4.6. Remaining useful life of the source (statutory factor 4)

Characterizing the remaining useful life of the source involves understanding how long the source will remain in operation as well as the expected lifespan of the potential control measures. The remaining useful life of an individual emission unit can vary greatly depending on the age of the unit, the size of the unit, maintenance schedules, and other factors.

U.S. EPA provides recommendations in its August 2019 Guidance, including different considerations depending on the type of source, in characterizing the remaining useful life of a source.[133] The guidance suggests that states can consider this factor by considering the useful life of a control measure, rather than the source itself, as the control measure is typically replaced with a similar system at the end of the useful life of the control measure. Subsequently, the annualized costs of a potential control measure are typically based on the expected useful life of the control measure instead of the remaining useful life of the source.

However, there are circumstances where the remaining useful life of the source is less than the expected useful life of the control measure. U.S. EPA clarifies that where an enforceable requirement exists for a source to cease operation, a state may use the enforceable shutdown date as the end of the remaining useful life.[134] The MPCA did consider expected shutdown dates for certain sources and

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[131] *See id.* at 33.
[132] *See* U.S. EPA, COST REPORTS AND GUIDANCE FOR AIR POLLUTION REGULATIONS*, supra.*
[133] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 33-34.
[134] *See id.* at 34.

emission units as discussed previously in Section 2.3.3 (see Table 31. Summary of emission unit retirements).

In general, facilities provided cost estimates that followed the recommendations in the Control Cost Manual, using the cost estimation spreadsheets when available, which provide typical values of the useful life of certain control measures (e.g., SNCR - 20 years, SCR - 30 years for utility boilers and 20-25 years for industrial boilers, wet/dry FGD - 20-30 years, etc.).[135]

The MPCA reviewed the control measure analyses that facilities provided, including the comments provided by FLMs, U.S. EPA, or Tribes, and made revisions to the cost estimates prepared to address the expected useful life of the control measure used in those estimates. Ultimately, the MPCA evaluated potential control measures using the expected useful life of the control measure as the remaining useful life as suggested by the August 2019 Guidance.

2.4.7. Visibility benefits

U.S. EPA clarifies in its August 2019 Guidance that states must consider the four statutory factors identified in 40 CFR § 51.308(f)(2) in determining reasonable progress and that states must consider those factors in the control analysis step.[136] The guidance also describes other information that may be considered when determining what measures are needed to make reasonable progress. U.S. EPA also provided additional information in its July 2021 Clarification Memo regarding the use of visibility benefits alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress.[137] The memo reiterates that other reasonable factors may be considered in reasonable progress determinations, so long as those factors are considered in a reasonable way that does not undermine or nullify the four statutory factors.[138]

MPCA has evaluated the control measure analyses submitted by all selected sources through consistently applying the four statutory factors to determine which measures are needed to make reasonable progress. The MPCA did not consider the visibility benefits of individual control measures alongside the four statutory factors when evaluating emission control measures. As a result, the MPCA believes it made a reasonable selection of factors to characterize in the control measure analysis. The result of the control measure analysis process is identified in Section 2.5.6 below.

2.4.8. Previous analyses and previously approved approaches

U.S. EPA provides additional clarification in its August 2019 Guidance regarding the documentation requirements of 40 CFR § 51.308(f)(2)(iii) for a state that references and relies on a previous analysis.[139] To satisfy the referenced requirement for documentation when relying on a previous analysis, a state could explain why it concludes that a previous analysis does not require an update.

The MPCA is both referencing and relying on the analyses conducted by U.S. EPA that determined what emission reductions were BART for the indurating furnaces at taconite facilities in Minnesota, as discussed earlier in Section 2.3.5 regarding sources that are effectively controlled. The BART analyses conducted by U.S. EPA were included in the Taconite Regional Haze FIPs promulgated in 2013 and 2016. U.S. EPA and the Minnesota taconite facilities have been in continued settlement discussions since the

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[135] *See* U.S. EPA, Cost Reports and Guidance for Air Pollution Regulations*, supra.*
[136] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 28.
[137] *See* July 2021 EPA Clarifications*, supra, at 12-13.*
[138] *See id.* at 4 (quoting U.S. EPA, Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans, EPA-HQ-OAR-2015-0531, at 156 (Dec. 2016)).
[139] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 36.

promulgation of these FIPs, as discussed previously in Section 1.3, most recently resulting in revisions to the FIP requirements for U.S. Steel - Minntac in 2020.

While the MPCA is not included in the settlement discussions between U.S. EPA and the Minnesota taconite facilities, the MPCA expects that U.S. EPA's current analysis is both sound and does not require an update for this implementation period given that U.S. EPA continues to evaluate the specific requirements of the FIP, including the associated BART emission limits.

2.5. Step 5 - Control measures necessary to make reasonable progress

The Regional Haze Rule requires that states make decisions on what emission control measures are necessary to make reasonable progress after identifying the relevant factors. All states, including those without Class I areas, are required to select sources for analysis and determine what emission control measures are necessary to make reasonable progress at the state's own Class I areas and Class I areas in other states and incorporate those control measures into their long-term strategy.

U.S. EPA has defined the methodology that states must use to determine what measures are necessary to make reasonable progress in 40 CFR § 51.308(f)(2).

> *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. … In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.*

The reasonable progress analysis must use the four factors identified in 40 CFR § 51.308(f)(2)(i) to evaluate and determine the emission reduction measures necessary to make reasonable progress. In its August 2019 Guidance U.S. EPA also suggests that states may consider other information in determining what measures are needed to make reasonable progress.[140] The examples U.S. EPA provides include the optional consideration of visibility benefits and the five additional factors listed in 40 CFR § 51.308(f)(2)(iv), if not already considered when selecting sources. A state that elects to consider these other factors must do so in a reasonable way that does not nullify the four statutory factors.[141]

Additionally, the Regional Haze Rule requires that the SIP must document how a state has done its analysis in 40 CFR § 51.308(f)(2)(i) and 40 CFR § 51.308(f)(2)(iii).

> *The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.*[142]
>
> *The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects. The State may meet this requirement by relying on technical analyses developed by a regional planning process and approved by all State participants.*[143]

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[140] *See id.* at 28.
[141] *See* July 2021 EPA Clarifications*, supra, at 12-13.*
[142] 40 CFR § 51.308(f)(2)(i).
[143] 40 CFR § 51.308(f)(2)(iii).

Furthermore, states are required to consider the emission reduction measures adopted by other contributing states, including all measures that have been agreed upon through interstate consultation. The Regional Haze Rule specifies these requirements in 40 CFR § 51.308(f)(2)(ii).

> *The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.*
>
> *(A) The State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.*
>
> *(B) The State must consider the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area.*

Additional detail regarding the emission control measures determined to be necessary to make reasonable progress by the MPCA is provided in the following sections.

2.5.1. Cost of compliance (statutory factor 1)

U.S. EPA states in its August 2019 Guidance that they anticipate the outcome of a decision-making process by a state regarding control measures may most often depend on how the state assesses the balance between the four statutory factors, specifically the cost of compliance, and the visibility benefits.[144] U.S. EPA continues by stating that the factors, other than cost, will either be subsumed into the cost of compliance or not be a major consideration, providing the following examples:

- The remaining useful life is considered by annualizing the costs of compliance.
- The time necessary for compliance is considered by setting a reasonable time period as a compliance deadline.
- The energy/non-air environmental impacts that cannot be incorporated into the cost estimate will be a significant influence on the control measure(s) considered in only unusual situations.[145]

However, this does not mean additional weight is given to the cost of compliance in MPCA's evaluation of the four-factor analyses provided and U.S. EPA specifically emphasizes that they are not recommending that states give particular or extra weight to the cost factor and visibility benefits. U.S. EPA reiterates that a state should generally make control decisions that are reasonably consistent among and across sources with the state. One example of consistency identified by the U.S. EPA is applying control measures to two sources of a similar type/size, when the new emission control measure has similar costs, if that control measures is applied to either source.[146]

Furthermore, U.S. EPA does not provide thresholds for metrics to evaluate control measures in its August 2019 Guidance and clarifies that while the Regional Haze Rule does not prevent states from implementing "bright line" thresholds, states must explain the basis for any thresholds when considering costs and visibility benefits.[147]

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[144] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 37.
[145] *See id.*
[146] *See id.* at 38.
[147] *See id.*

While the MPCA did not consider thresholds for visibility metrics, see Section 2.5.5 for additional discussion on visibility benefits, the control measures were evaluated by examining the cost effectiveness (i.e., the cost per ton of pollutant reduced). U.S. EPA also provides recommendations for states that apply a cost per ton threshold to evaluate control measures, specifically recommending that the Regional Haze SIP explain why the threshold is appropriate and consistent with the requirement to make reasonable progress. One example provided is a comparison to the cost per ton values for control measures implemented previously as part of the first regional haze implementation period or for other Clean Air Act requirements.[148]

U.S. EPA did not specify a “bright line” threshold for states to use in evaluating the costs of compliance and determining whether control measures are cost-effective or not. As a result, the MPCA chose to review available cost information from similar control measure evaluations as part of the process to evaluate potential control measures. The process and criteria that MPCA used to evaluate the cost of compliance were:

- A review of sources that identify information regarding cost effectiveness to help inform the decision-making process, including:
- The BART and reasonable progress determinations from the first implementation period
- Other states’ Regional Haze SIP submittals in this implementation period that were available for public notice and review at the time (as of roughly October 2021)
- U.S. EPA’s RACT/BACT/LAER Clearinghouse (RBLC) that contains the results of analyses that are conducted in a similar manner to the four-factor analyses as a comparison for cost effectiveness.
- Make initial recommendations for NO_X and SO_2 control strategies based on cost information provided by facilities compared to the cost information available in the above resources.
- Provide the MPCA’s initial assessment of control measures to the facilities that prepared four-factor analyses and indicated that MPCA would consider alternatives that achieved emission reductions greater than or equal to the reductions that would be achieved by the recommended control measures.
- Facilities were also provided the opportunity to further refine the cost estimates by obtaining source-specific vendor quotes for the installation of the control measure(s) and providing that information to the MPCA.
- Adjust the cost information provided by facilities for consistency across emission units in the basic factors used in the cost estimates (e.g., interest rate, retrofit factors, etc.).
- Determine the cost-effective controls from the four-factor analyses that are necessary to continue making reasonable progress.

Cost-effectiveness (first implementation period). From the first regional haze implementation period, the BART and reasonable progress determinations that included cost-effectiveness were sources of cost data used to inform the MPCA’s decision making process. The MPCA was also asked to provide input on a similar effort conducted by the Arkansas Department of Energy and Environment’s Division of Environmental Quality (Arkansas DEQ). The Arkansas DEQ complied the costs of control determinations for BART and reasonable progress in the first planning period and scaled the cost per ton values in each determination to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). The analysis excluded any BART-alternatives because many BART alternatives were either trading programs or were operational changes made by facilities instead of technology-specific changes with associated cost data. This analysis found that the cost-effectiveness of controls installed as a result of the first regional haze implementation period were generally $5,200 per ton of pollutant reduced. A copy of this cost

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[148] *See id.* at 37-40.

compilation is included in Appendix F. Arkansas DEQ - BART and Reasonable Progress Determination Cost Evaluation.

Cost-effectiveness (other states' Regional Haze SIPs). The MPCA also reviewed the cost-effectiveness values identified in Regional Haze SIPs that had been made available for public notice and review at the time (as of roughly October 2021). This review included Arkansas, Arizona, Colorado, North Dakota, New Mexico, Oregon, Texas, Washington, and Wisconsin; and found that the cost-effectiveness thresholds used by these states ranged from roughly $1,000 to $10,000 per ton of pollutant reduced. Minnesota did not choose a single state as a guide but did consider its cost effectiveness threshold of $7,600/ton to be within the range of other state proposals.

Cost-effectiveness (U.S. EPA's RBLC). The RBLC is a database that contains the results of analyses that are conducted in a similar manner to the four-factor analyses and provide a useful comparison for considering the cost-effectiveness of potential control measures. The MPCA focused on reviewing the information available for industrial boilers as they are primary the emission units that are of interest in the four-factor analyses for Minnesota facilities. MPCA's review encompassed boilers that burn coal, biomass, and other solid fuel with design heat input capacities greater than 250 MMBtu/hr (identified as process types 11.11, 11.12, and 11.19), heat input capacities of 100-250 MMBtu/hr (identified as process types 12.11, 12.12, and 12.19), and heat input capacities of less than 100 MMBtu/hr (identified as process types 13.11 and 13.12). In this analysis, MPCA only found cost data for 11 coal-fired boilers (greater than 250 MMBtu/hr) that ranged from $158 to $9,242 per ton of pollutant reduced (NO_X or SO_2).

Evaluating the cost of compliance. The MPCA evaluated the cost of compliance of control measures by comparing the above sources of information to determine what control measures were generally cost-effective. While MPCA did not use a specific threshold to uniformly determine whether a control measure was cost-effective or not, the MPCA did use an initial screening threshold of roughly $10,000 per ton to determine which control measures to focus on. Control measures that cost more than $10,000 per ton were determined to be likely not cost-effective in this implementation period. An overview of the costs associated with the control measures provided by the facilities, and the MPCA's revisions to those costs, are discussed previously in Section 2.4.3. Based on the costs associated with certain control measures, the MPCA identified six facilities where control measures appeared cost-effective. This recommendation was made based on the cost information for these control measures compared to the above sources of cost-effectiveness data. Ultimately, the controls that MPCA identified as potentially cost-effective for this regional haze implementation period cost less than approximately $7,600 per ton of pollutant reduced. Additional information for specific facilities is provided below.

American Crystal Sugar - Crookston & East Grand Forks. The MPCA's initial recommendation was that these facilities install NO_X and SO_2 controls, as identified below, based on the information provided in the facilities' four-factor analyses. These were the previous cost estimates before being updated by the facility to account for the additional PM controls needed for the dry sorbent injection SO_2 controls. Without new PM controls, the facility has stated they will potentially run into compliance issues for the PM limits that apply to the boilers given the uncertainty of the impact of sorbent injection without site-specific testing. The new PM controls included in the revised cost estimates allow for an increased SO_2 reduction (i.e., a 70% reduction instead of a 50% reduction) but also have an increased cost.

The facility provided the updated NO_X control information to MPCA on February 22, 2022. The facility pursued a quote from an SNCR equipment vendor regarding the achievable NO_X reduction and the technical feasibility of implementing SNCR at the facility. The main takeaway from the vendor information is that some NO_X reduction is still possible, but at a lower effectiveness (10% - 25%

depending on the boiler vs. the 30% originally expected). The lower reduction percentage comes from the process temperature being hotter than the optimal range for the NO_X reduction reaction to occur.

Additionally, the MPCA generally revised the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates as discussed previously in Section 2.4.3. Copies of the MPCA-revised cost estimates are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions. See the table below for a summary of the updates to control measure costs.

Table 54. American Crystal Sugar - Control measure evaluation

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Originally recommended SO_2 controls						
American Crystal Sugar - Crookston	Boiler 1	DSI	121	$2,318,900	$484,800	$4,023
	Boiler 2	DSI	121	$2,318,900	$484,800	$4,023
	Boiler 3	DSI	127	$2,154,700	$526,700	$4,164
American Crystal Sugar - East Grand Forks	Boiler 1	DSI	226	$4,072,500	$759,000	$3,356
	Boiler 2	DSI	226	$4,072,500	$759,000	$3,356
Originally recommended NO_X controls						
American Crystal Sugar - East Grand Forks	Boiler 1	SNCR	91	$5,825,675	$596,238	$6,583
	Boiler 2	SNCR	91	$5,825,675	$596,238	$6,583
Revised SO_2 control information (American Crystal Sugar vendor quote)						
American Crystal Sugar - Crookston	Boiler 1	DSI w/ FF	169	$12,069,333	$2,357,100	$13,972
	Boiler 2	DSI w/ FF	169	$12,069,333	$2,357,100	$13,972
	Boiler 3	DSI w/ FF	177	$12,069,333	$2,357,100	$13,309
American Crystal Sugar - East Grand Forks	Boiler 1	DSI w/ FF	317	$18,314,200	$3,773,250	$11,917
	Boiler 2	DSI w/ FF	317	$18,314,200	$3,773,250	$11,917
Revised NO_X control information (American Crystal Sugar vendor quote)						
American Crystal Sugar - East Grand Forks	Boiler 1	SNCR	29	$5,401,600	$491,728	$17,009
	Boiler 2	SNCR	29	$5,401,600	$491,728	$17,009
Revised SO_2 control information (MPCA revisions)						
American Crystal Sugar - Crookston	Boiler 1	DSI w/ FF	169	$12,069,333	$2,216,133	$13,137
	Boiler 2	DSI w/ FF	169	$12,069,333	$2,216,133	$13,137
	Boiler 3	DSI w/ FF	177	$12,069,333	$2,216,133	$12,513
American Crystal Sugar - East Grand Forks	Boiler 1	DSI w/ FF	317	$18,314,200	$3,559,350	$11,241
	Boiler 2	DSI w/ FF	317	$18,314,200	$3,559,350	$11,241
Revised NO_X control information (MPCA revisions)						
American Crystal Sugar - East Grand Forks	Boiler 1	SNCR	35	$5,417,537	$540,063	$15,366
	Boiler 2	SNCR	35	$5,417,537	$540,063	$15,366

Based on the additional information provided by the facility, neither NO_X nor SO_2 controls appear to be cost-effective for either facility in this regional haze implementation period.

Hibbing Public Utilities Commission. The MPCA's initial recommendation was that this facility install NO_X controls, as identified below, based on the information provided in the facility's four-factor analysis.

The facility prepared these cost estimates using 1999 - 2001 U.S. EPA memos that examined the costs of control systems at electric generating units (EGUs) and scaling those dollar values to today. MPCA updated these cost estimates to use U.S. EPA's control cost manual cost estimation spreadsheets instead of the 1999-2001 U.S. EPA memos used by the facility.[149]

On May 10, 2022, the Regulated Party presented a revised operations plan for the facility, referred to as the "Hibbing Public Utilities Restorative Plan", to the Hibbing Public Utilities Commission, that outlined the use of renewable resources such as wood alongside with natural gas as the primary fuels for the boilers at HPU. Coal was identified as a backup/emergency fuel to manage natural gas price fluctuations and power grid volatility. The Hibbing Public Utilities Commission formally adopted the Hibbing Public Utilities Restorative Plan on May 24, 2022.

On July 1, 2022, the Regulated Party prepared and provided a memorandum identifying the adopted Hibbing Public Utilities Restorative Plan; indicating that HPU plans to make coal a backup fuel for Boiler 1 and Boiler 3, and that Boiler 2 is not currently able to combust coal without additional maintenance, which HPU is not pursuing at this time. The currently allowable fuels for Boiler 1, Boiler 2, and Boiler 3 are coal, used oil, natural gas, and oily cellulose-based sorbents (including rags) as identified in Air Emissions Permit No. 13700027-102.

Additionally, the MPCA generally revised the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates as discussed previously in Section 2.4.3. Copies of the MPCA-revised cost estimates are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions. See the table below for a summary of the updates to control measure costs.

Table 55. Hibbing Public Utilities Commission - Control measure evaluation

Facility	Emission unit	Control strategy	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Originally recommended NO_X controls						
Hibbing Public Utilities Commission	Boiler 1	SNCR	43	$474,810	$305,076	$7,067
	Boiler 2	SNCR	43	$474,810	$305,076	$7,067
	Boiler 3	SNCR	58	$570,839	$366,777	$6,365
Revised NO_X control information (MPCA revisions)						
Hibbing Public Utilities Commission	Boiler 1	SNCR	45	$3,143,455	$294,673	$6,592
	Boiler 2	SNCR	45	$3,143,455	$294,673	$6,592
	Boiler 3	SNCR	53	$3,383,762	$320,080	$6,004

Based on the additional information provided by the facility, NO_X controls remain cost effective for the facility in this regional haze implementation period However, instead of installing potential controls the facility accepted limits on NO_X emissions for the boilers that resulted in equivalent reductions that would have been achieved with installing SNCR on each boiler. These limits were incorporated into an enforceable agreement that includes requirements for the facility to calculate, track, record, and report annual NO_X emissions from the boilers beginning on January 1, 2023. A copy of the enforceable agreement is available in Appendix D. MPCA Administrative Orders.

Northshore Mining - Silver Bay. Power Boilers 1 and 2 at the facility are currently permitted to operate, but the facility indicated that these units are planned to be idled through 2031 as part of a voluntary

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

power supply agreement that the facility entered into with Minnesota Power to purchase grid electrical power alongside the idling of Power Boilers 1 and 2. As of October 2019, Power Boilers 1 and 2 have been idled. The facility indicated that the idled boilers may resume operation after the termination of the agreement with Minnesota Power in 2031, but a typical operating scenario has not yet been determined.

The facility expects that Power Boilers 1 and 2 will generate no emissions through the second regional haze planning period (2028) and projected the NO_X and SO_2 emission rates of Power Boilers 1 and 2 as zero in evaluating the cost-effectiveness metric (in dollars per ton of pollutant removed) for the control technologies examined in the four-factor analysis. Based on the analysis, the facility concluded that additional control measures on Power Boilers 1 and 2, beyond the existing measures, are not required to make reasonable progress as there will be no emissions removed by the installation of any control technology.

The MPCA's recommendation was that the idling of the boilers through 2031 be incorporated in an enforceable agreement that specifies the actions the facility would take should the boilers resume operation prior to the end of 2031. The MPCA also evaluated the information provided in the facility's four-factor analysis as if the boilers were operating at historical levels to determine if any NO_X or SO_2 controls may be cost-effective.

Additionally, the MPCA generally revised the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates as discussed previously in Section 2.4.3. Copies of the MPCA-revised cost estimates are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions. See the table below for a summary of the updates to control measure costs.

Table 56. Northshore Mining Silver Bay - Control measure evaluation

Facility	**Emission unit**	**Control measure**	**Emission reduction (tpy)**	**Capital costs ($)**	**Annual costs ($)**	**Cost effectiveness ($/ton)**
Original SO_2 control information						
Northshore Mining - Silver Bay	Power Boiler 1	DSI	-	$34,463,571	$6,144,640	-
		Spray Dry Absorber	-	$58,737,702	$12,796,563	-
	Power Boiler 2	DSI	-	$37,737,598	$6,943,044	-
		Spray Dry Absorber	-	$61,962,015	$13,572,909	-
Original NO_X control information						
Northshore Mining - Silver Bay	Power Boiler 1	SNCR	-	$7,239,275	$992,019	-
		SCR	-	$40,647,490	$4,159,366	-
	Power Boiler 2	SNCR	-	$8,917,925	$1,435,176	-
		LNB+OFA	-	$11,609,362	$1,725,870	-
		SCNR+LNB+OFA	-	$20,527,287	$3,161,046	-
		SCR	-	$55,724,684	$5,985,367	-
		SCR+LNB+OFA	-	$67,334,046	$7,711,237	-

Facility	Emission unit	Control measure	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Revised SO_2 control information (MPCA revisions)						
Northshore Mining - Silver Bay	Power Boiler 1	DSI	732	$28,001,651	$4,946,246	$6,754
		Spray Dry Absorber	942	$58,737,702	$9,618,924	$10,216
	Power Boiler 2	DSI	546	$30,661,798	$5,628,525	$10,305
		Spray Dry Absorber	702	$61,962,015	$10,221,871	$14,555
Revised NO_X control information (MPCA revisions)						
Northshore Mining - Silver Bay	Power Boiler 1	SNCR	167	$5,929,287	$819,324	$4,916
		SCR	533	$33,130,713	$2,792,174	$5,236
	Power Boiler 2	SNCR	252	$7,262,749	$1,015,960	$4,031
		LNB+OFA	403	$11,609,362	$1,555,019	$3,856
		SCNR+LNB+OFA	554	$18,872,111	$2,570,979	$4,637
		SCR	806	$45,313,042	$3,813,166	$4,728
		SCR+LNB+OFA	887	$56,922,404	$5,368,185	$6,051

Based on MPCA's revised cost information and selected historical emissions data, cost-effective NO_X control measures for both boilers and cost-effective SO_2 control measures for Boiler 1 may exist if the boilers were to continue operating at historical emission rates. However, as future operating plans or scenarios beyond 2031 (including production rates, fuel utilization, and emissions) are not reasonably foreseeable MPCA has not made any determination regarding whether additional controls are necessary to continue making reasonable progress. For the second regional haze implementation period, the idling of the boilers was incorporated into an enforceable agreement as discussed in Section 2.3.3. Therefore, the facility was removed from further analysis. This enforceable agreement includes a requirement for the facility to provide the anticipated operating scenario, expected emission rates under that operating scenario, and an updated four-factor analysis of NO_X and SO_2 controls for the boilers if they resume operation prior to 2031. If the boilers resume operation prior to 2031, the facility and MPCA will revisit and revise the four-factor analyses, as well as the enforceable agreement, for these boilers as part of the Regional Haze Progress Report due to U.S. EPA in 2025 and the Regional Haze Comprehensive Update due to U.S. EPA in 2028 for the third implementation period. A copy of the enforceable agreement is available in Appendix D. MPCA Administrative Orders.

Sappi Cloquet. The MPCA's initial recommendation was that this facility install NO_X controls, as identified below, based on the information provided in the facility's four-factor analysis.

These were previous cost estimates before being updated after further discussion with control equipment vendors. The facility was specifically reviewing costs and vendor quotes for an SNCR system as the original analysis was based on an analysis from roughly 10 years ago. The facility provided the updated NO_X control information to MPCA on March 29, 2022. Preliminary costs from the updated analysis are based on a vendor quote that the facility pursued to update the estimated capital costs.

Additionally, the MPCA generally revised the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates as discussed previously in Section 2.4.3. Copies of the MPCA-revised cost estimates are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions. See the table below for a summary of the updates to control measure costs.

Table 57. Sappi Cloquet - Control measure evaluation

Facility	Emission unit	Control strategy	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Originally recommended NO_X controls						
Sappi Cloquet	Boiler 9	SNCR	87	$5,408,165	$662,190	$7,632
Revised NO_X control information (Sappi vendor quote)						
Sappi Cloquet	Boiler 9	SNCR	87	$6,068,270	$826,547	$9,527
Revised NO_X control information (MPCA revisions)						
Sappi Cloquet	Boiler 9	SNCR	87	$6,068,270	$742,887	$8,562

Based on the additional information provided by the facility, NO_X controls no longer appear cost effective for the facility in this regional haze implementation period.

Southern Minnesota Beet Sugar Cooperative. The MPCA's initial recommendation was that this facility install NO_X controls, as identified below, based on the information provided in the facility's four-factor analysis.

The facility indicated in a meeting with MPCA on February 14, 2022, that they don't believe that MPCA has a lawful basis to require the facility to install these controls as part of the regional haze program. The facility reiterated that they don't believe they should have been part of the sources evaluated in the four-factor analyses. The reasons the facility provided generally included that they are far away to the southwest from the Class I areas (Boundary Waters and Voyageurs) and prevailing winds are from the northwest and southeast. To support its contentions, the facility provided a trajectory analysis. Southern Minnesota Beet Sugar Cooperative argues that the cost of controls on a dollar per ton of pollutant removed basis are not cost-effective in producing visibility improvement, with the principal disagreement being whether they should be required in general. The facility provided a written version of their comments and position on MPCA's initial recommendation on March 14, 2022.

On April 20, 2022, the MPCA responded to the facility reiterating MPCA's approach to source selection and evaluating potential control measures. In summary, the MPCA stated that it selected sources to be analyzed, including Southern Minnesota Beet Sugar Cooperative, and determined what measures are necessary to make reasonable progress by following the requirements of the Regional Haze Rule alongside the guidance that U.S. EPA issued for this regional haze implementation period. As discussed, MPCA did not evaluate individual source visibility improvements nor the facility's trajectory analysis. The MPCA did not evaluate visibility analyses prepared by any facilities as discussed in Sections 2.4.7 and 2.5.5. MPCA's recommendation that the facility install SNCR on Boiler 1 is neither unjustified nor arbitrary as the facility claims.

Additionally, the MPCA generally revised the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates as discussed previously in Section 2.4.3. Copies of the MPCA-revised cost estimates are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions. See the table below for a summary of updates to control measure costs.

Table 58. Southern Minnesota Beet Sugar Cooperative - Control measure evaluation

Facility	Emission unit	Control strategy	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Originally recommended NO_X controls						
Southern Minnesota Beet Sugar Coop	Boiler 1	SNCR	340	$6,908,987	$1,297,449	$3,815
Revised NO_X control information (MPCA revisions)						
Southern Minnesota Beet Sugar Coop	Boiler 1	SNCR	447	$7,159,267	$1,314,072	$2,942

No additional information provided by the facility suggests that the NO_X controls are not cost-effective for the facility in this regional haze implementation period. The MPCA maintains that the NO_X controls are cost-effective and necessary to continue making reasonable progress, but the MPCA has not reached an agreed path forward with the facility to install the NO_X controls.

Virginia Department of Public Utilities. The MPCA's initial recommendation was that this facility install NO_X controls, as identified below, based on the information provided in the facility's four-factor analysis.

The facility prepared these cost estimates using 1999-2001 U.S. EPA memos that examined the costs of control systems at electric generating units (EGUs) and scaling those dollar values to today. MPCA updated these cost estimates to use U.S. EPA's control cost manual cost estimation spreadsheets instead of the 1999-2001 U.S. EPA memos used by the facility.[150] Additionally, the facility indicated in a meeting with MPCA on February 16, 2022, that they were contemplating the future operations of Boiler 7 and limiting coal usage in the boiler, to qualify as a "limited use boiler" under the federal standards for boilers in 40 CFR Part 63 Subpart DDDDD, as an alternative emission reduction strategy. The facility also indicated that the boiler will likely retire prior to 2028, but they were not certain of the exact date at the time. On April 6, 2022, the facility provided a memorandum that identified the planned retirement of Boiler 7 by January 1, 2025.

Additionally, the MPCA generally revised the interest rate used, the cost of electricity, reagents, and/or fuel, and the retrofit factor applied to the cost estimates as discussed previously in Section 2.4.3. Copies of the MPCA-revised cost estimates are available in Appendix E. Four-Factor Analyses - MPCA Cost Revisions. See the table below for a summary of updates to control measure costs.

Table 59. Virginia Department of Public Utilities - Control measure evaluation

Facility	Emission unit	Control strategy	Emission reduction (tpy)	Capital costs ($)	Annual costs ($)	Cost effectiveness ($/ton)
Originally recommended NO_X controls						
Virginia Department of Public Utilities	Boiler 7	SNCR	20	$227,686	$146,294	$7,215
Revised NO_X control information (MPCA revisions)						
Virginia Department of Public Utilities	Boiler 7	SNCR	28	$2,961,727	$269,972	$9,534

Based on the additional information provided by the facility, NO_X controls no longer appear cost effective for the facility in this regional haze implementation period. However, the retirement of the

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

boiler was incorporated into an enforceable agreement as discussed in Section 2.3.3 and the facility was removed from further analysis. A copy of the enforceable agreement is available in Appendix D. MPCA Administrative Orders.

2.5.2. Time necessary for compliance (statutory factor 2)

In its August 2019 Guidance, U.S. EPA clarifies that the time necessary for compliance enters into the decision-making process in a different way than the other three statutory factors.[151] Specifically, U.S. EPA states that while the high costs of compliance, adverse energy and non-air environmental impacts, or a short remaining useful life may suggest that a control measure is not needed to continue making reasonable progress, the time necessary for compliance does not present the same barrier. The reasoning U.S. EPA provides on this topic is that the time perspective for the Regional Haze program is long and extends beyond the time necessary to install and "shake down" any control measure.[152]

In general, U.S. EPA recommends that states consider the time necessary for compliance as part of when a control measure can be reasonably achieved while the other three factors determine what control measure(s), or how much progress, is reasonable.[153]

As discussed previously in Section 2.4.4, the MPCA considered the time necessary for compliance as part of evaluating potential control measures later in the four-factor analysis process and not as a specific factor in determining if a control measure was needed to make reasonable progress. This approach is consistent with the concepts identified in U.S. EPA's August 2019 Guidance as discussed above.

2.5.3. Energy and non-air environmental impacts (statutory factor 3)

In its August 2019 Guidance, U.S. EPA recommends that states consider energy and non-air environmental impacts by accounting for any increases or decreases in energy use, water use, waste generation/disposal, and other impacts as part of the costs of compliance.[154] U.S. EPA also identifies that states may consider the benefits of non-air quality environmental impacts and that the Clean Air Act does not require states to consider air deposition impacts, including the effects on water, soil, and vegetation, when determining the controls needed to continue making reasonable progress.[155]

As discussed previously in Section 2.4.5, the MPCA consider the energy and non-air environmental impacts as part of the cost of compliance of potential control measures and not as separate impacts in determining whether a control measure was necessary to make reasonable progress. This approach is consistent with the concepts identified in U.S. EPA's guidance as discussed above.

2.5.4. Remaining useful life of the source (statutory factor 4)

In its August 2019 Guidance, U.S. EPA recommends that states consider the remaining useful life factor by using it to calculate emission reductions, annualized compliance costs, and cost effectiveness values.[156] As discussed previously in Section 2.4.6, the MPCA considered the remaining useful life as part of the cost of compliance as U.S. EPA recommends.

The MPCA did consider expected shutdown dates for certain sources and emission units as discussed previously in Section 2.3.3 (see Table 31. Summary of emission unit retirements). Specifically, the MPCA

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[151] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 41.
[152] *See id.*
[153] *See id.*
[154] *See id.* at 41-42.
[155] *See id.*
[156] *See id.* at 42.

determined control measures that otherwise appeared cost effective for emission units at Virginia Department of Public Utilities, were not needed to continue making reasonable progress given that enforceable requirements regarding the useful life of those emission units were established. Copies of these enforceable agreements are available in Appendix D. MPCA Administrative Orders.

2.5.5. Visibility benefits

U.S. EPA clarifies in its August 2019 Guidance that states must consider the four statutory factors identified in 40 CFR § 51.308(f)(2) in determining reasonable progress and that states must consider those factors in the control analysis step.[157] The guidance also describes other information that may be considered when determining what measures are needed to make reasonable progress. U.S. EPA also provided additional information in its July 2021 Clarification Memo regarding the use of visibility benefits alongside the four statutory factors when determining the emission reduction measures that are necessary to make reasonable progress.[158] The memo reiterates that other reasonable factors may be considered in reasonable progress determinations, so long as those factors are considered in a reasonable way that does not undermine or nullify the four statutory factors.[159]

MPCA has evaluated the control measure analyses submitted by all selected sources through consistently applying the four statutory factors to determine which measures are needed to make reasonable progress. The MPCA did not consider the visibility benefits of individual control measures alongside the four statutory factors when evaluating emission control measures. As a result, the MPCA believes it made a reasonable selection of control measures necessary to make reasonable progress in this implementation period. The result of the control measure analysis process is identified in Section 2.5.6 below.

2.5.6. Establishing emission limitations, compliance schedules, and other measures necessary to make reasonable progress

The Regional Haze Rule requires that states develop a long-term strategy as specified in 40 CFR § 51.308(f)(2).

> ***Long-term strategy for regional haze.*** *Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to (f)(2)(i) through (iv). In establishing its long-term strategy for regional haze, the State must meet the [requirements of 40 CFR § 51.308(f)(2)(i)-(iv)].*

U.S. EPA reiterates in its August 2019 Guidance, that this provision requires SIPs to include enforceable emission limitations and/or other measures to address regional haze, compliance deadlines, and provisions to make those measures practicably enforceable including averaging times, monitoring requirements, recordkeeping, and reporting requirements.[160]

As discussed previously in Section 2.3.3, the MPCA relied on retirement dates that were used in the determination that no additional control measures were needed to continue making reasonable

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[157] *See id.* at 28.
[158] *See* July 2021 EPA Clarifications*, supra, at 12-13.*
[159] *See id.* at 4 (quoting U.S. EPA, Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans, EPA-HQ-OAR-2015-0531, at 156 (Dec. 2016)).
[160] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 42-43.

progress in this implementation period for certain sources. Where the retirement dates were not already incorporated into the source's Title V operating permit, the MPCA established enforceable requirements, via an administrative order, for the proposed retirement dates. Table 31 in Section 2.3.3 identifies the emission units that were excluded from the control measure analysis, the associated retirement dates, and the mechanism that establishes those retirement dates as enforceable.

Furthermore, the MPCA relied on certain sources already having effective controls in place as part of determining that no additional control measures were needed to continue making reasonable progress in this implementation for those sources. No additional actions were needed to make these control measures enforceable as the measures have been previously incorporated into the source's Title V operating permit or are required through a different mechanism. Table 32 in Section 2.3.5 identifies the emission units that were excluded from the control measure analysis, a summary of what controls or measures in place support an effectively controlled determination, and the mechanism that establishes those controls as enforceable.

U.S. EPA clarifies in its August 2019 Guidance that if a source is not selected for an analysis of control measures, the long-term strategy is not required to include emission limits for the source. U.S. EPA continues that in this circumstance, the state is not determining that any particular controls on the source are necessary to continue making reasonable progress, rather it is deferring a determination on that source until a later implementation period.[161] Therefore, the sources that the MPCA evaluated in the various steps outlined above and removed from further analysis due to the remaining useful life of the source or a determination that the source was effectively controlled do not require any additional enforceable requirements surrounding emissions from these sources.

As stated previously in Section 2.5.1 for Hibbing Public Utilities Commission, the MPCA reached an agreed path forward with the facility to establish NO_X emission limits as an alternative to installing the identified cost-effective NO_X controls. The MPCA established enforceable requirements, via an administrative order, for the proposed NO_X emission limits. A copy of this enforceable agreement is available in Appendix D. MPCA Administrative Orders.

However, as stated previously in Section 2.5.1 for Southern Minnesota Beet Sugar Cooperative, the MPCA has not reached an agreed path forward with the facility to install the identified cost-effective NO_X controls prior to providing this Regional Haze SIP for public notice and comment. The MPCA reiterates that the NO_X controls are cost-effective and necessary to continue to make reasonable progress based on following the requirements of the Regional Haze Rule and U.S. EPA's guidance issued for this implementation period. Southern Minnesota Beet Sugar Cooperative's reasons for disagreement are summarized in Section 2.5.1 and their correspondence is attached in Appendix B. Four-Factor Analyses - Facility Responses.

2.5.7. Northeast Minnesota Plan

Minnesota's Class I areas are located in the Northeastern region of the state. This area, also known as the Arrowhead or Iron Range, contains several major industrial sources that are high emitters of NO_X and SO_2 emissions. These high emitters include EGUs and the taconite industry, a unique iron ore mining and processing industry with only eight operating facilities in the United States, six of which are located in Northeast Minnesota. In the first regional haze implementation period the MPCA, in cooperation with FLMs and extensive stakeholder input, developed a concept plan that set emission reduction targets in the six counties closest to the Boundary Waters and Voyageurs Class I areas (Carlton, Cook, Itasca,

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[161] *See id.*

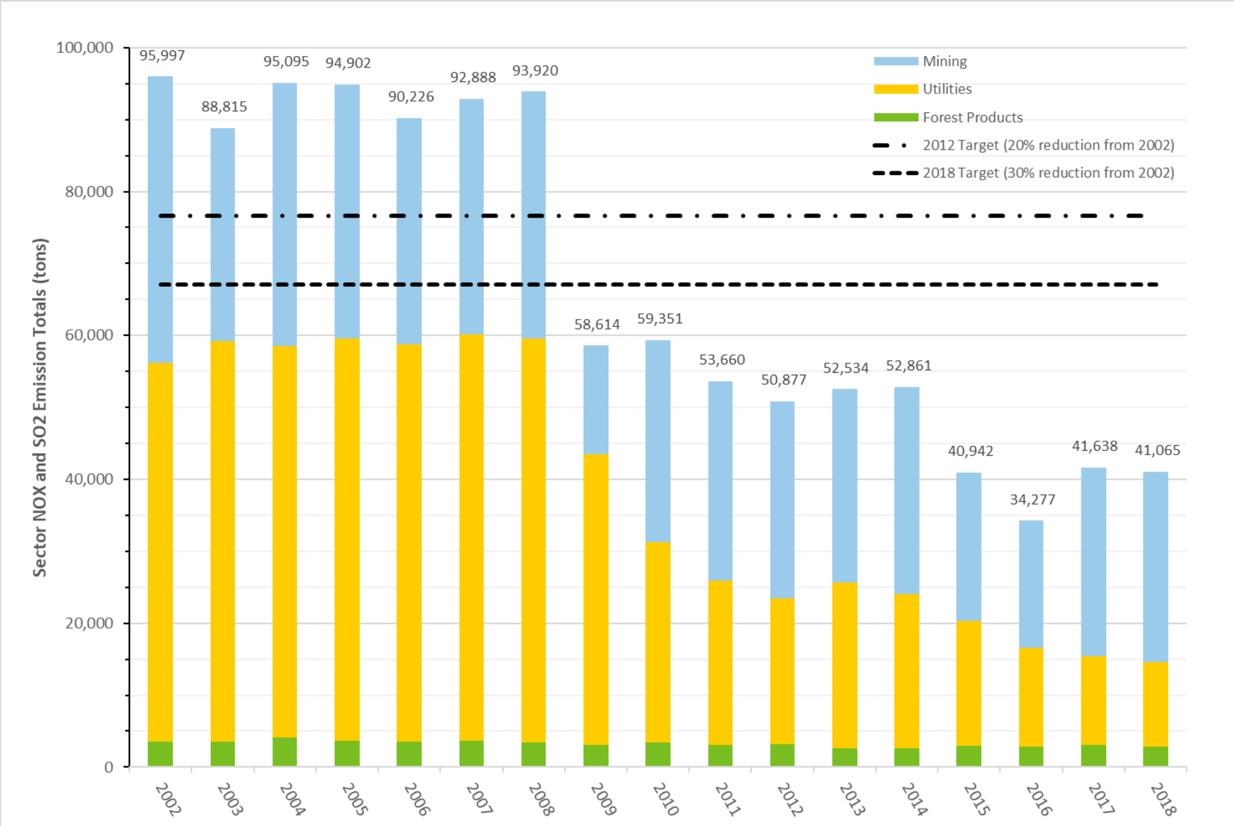
Koochiching, Lake, and St. Louis). The Northeast Minnesota Plan focused on this region as the MPCA's analysis of 2002 emissions from the top 18 emitting point sources within Minnesota showed that sources from this region comprised just one third of the total emissions but provided two thirds of the total visibility impact.

At the time the 2018 reasonable progress goal for both Class I areas was above the URP line, so the emission reduction targets were created by focusing on the controllable emissions from sources within Minnesota. The emission reduction targets were derived from the URP line for Voyageurs, using the amount of visibility impairment caused by NO_X and SO_2 emissions, and calculating the percent decrease in light extinction due to particles of ammonium nitrate and ammonium sulfate caused by NO_X and SO_2 emissions. The calculations determined a 28% reduction in light extinction from these particles was needed, by assuming the light extinction changed directly proportional to the change in emissions from the region. Ultimately, this led to non-binding emission reduction targets of a 20% reduction from 2002 emissions by the year 2012 and a 30% reduction from 2002 emissions by the year 2018.

The MPCA has continued to track NO_X and SO_2 emissions from the sources included in the Northeast Minnesota Plan since the plan's creation and publishes annual emissions from the tracked sources in the region, as well as the most recent monitored visibility conditions, on its external webpage.[162] Data from 2018 shows a combined NO_X and SO_2 reduction of roughly 55% from the 2002 base year, largely due to reductions from the utility sector. Figure 10 below displays the combined NO_X and SO_2 emissions from tracked sources in comparison to the 2002 and 2018 emission reduction targets.

[162] MPCA, *Northeast Minnesota Plan Sector Emissions*, MINNESOTA'S REGIONAL HAZE STATE IMPLEMENTATION PLAN, https://www.pca.state.mn.us/air/minnesotas-regional-haze-state-implementation-plan (last visited June 23, 2022).

Figure 10. Northeast MN Plan - Tracked emissions (2002 - 2018) and emission reduction targets



As discussed previously in Section 2.2.3, the MPCA evaluated the contributions from northeast Minnesota separately from the rest of the state for the Northeast Minnesota Plan. While visibility impairment at the Boundary Waters and Voyageurs Class I areas has significantly improved, emissions from the six-county region continue to comprise a significant portion of the visibility impacts in these areas. However, in this implementation period, the reasonable progress goals (RPGs) for 2028 at the Boundary Waters and Voyageurs are below the URP line (see Section 2.6.2 for more detail).

In this implementation period, the MPCA decided to carry forward the Northeast Minnesota Plan and establish new non-binding emission reduction targets for the years associated with the 2025 progress report and the 2028 comprehensive update. The MPCA set the new emission reduction targets using 2018 as the baseline year, instead of 2016, due to some industrial facilities that were idled or operating at reduced capacity in 2016, as a 30% reduction by 2025 and a 40% reduction by 2028. These emission reduction targets are comparable to the emission rates used in the modeling analysis (i.e., roughly a 32% reduction in combined NO_X and SO_2 emissions (2016 - 2028) in NE Minnesota) and the 40% reduction target aims for a larger emission reduction than currently modeled to capture the emission reduction measures that did not make it into the modeling effort (see Section 2.6.2 and Table 65 for additional detail).

Figure 11 below displays the combined NO_X and SO_2 emissions from tracked sources in comparison to the 2025 and 2028 emission reduction targets. The figure is presented using the same scale as Figure 10 above for consistency and displays emissions through 2021. Please note that the 2021 emissions data is still draft and will likely change after the 2021 Minnesota annual emissions inventory is finalized.

Figure 11. Northeast MN Plan - Tracked emissions (2012 - 2028) and new emission reduction targets

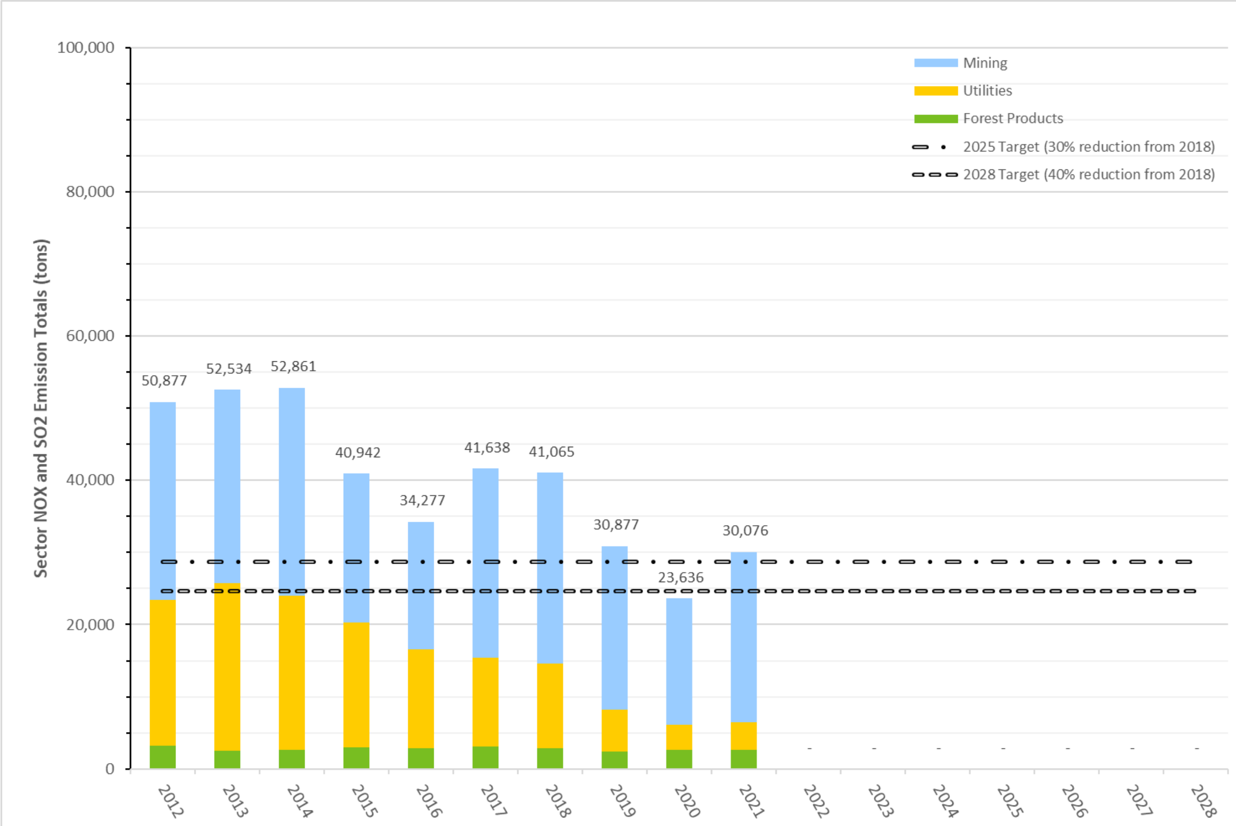


Figure 12 below displays the combined NO_X and SO_2 emissions (2016 - 2018) from tracked sources, the 2025 and 2028 emission reduction targets, and includes the modeled emissions for 2016 and 2028 for the tracked sources to help provide a comparison between the reduction targets and the emission rates used in the modeling analysis. Emissions inputs for the 2016 model platform are discussed in more detail in Section 2.6.1, included a detailed explanation of the 2016 base year and 2028 future year inventories. In the figure, 2016* represents emissions as modeled for the 2016 base year, 2028* represents the projected emissions as modeled for 2028, and 2028** represents the projected emissions as modeled for 2028 with additional adjustments made to account for emission reductions not included modeling analysis described below.

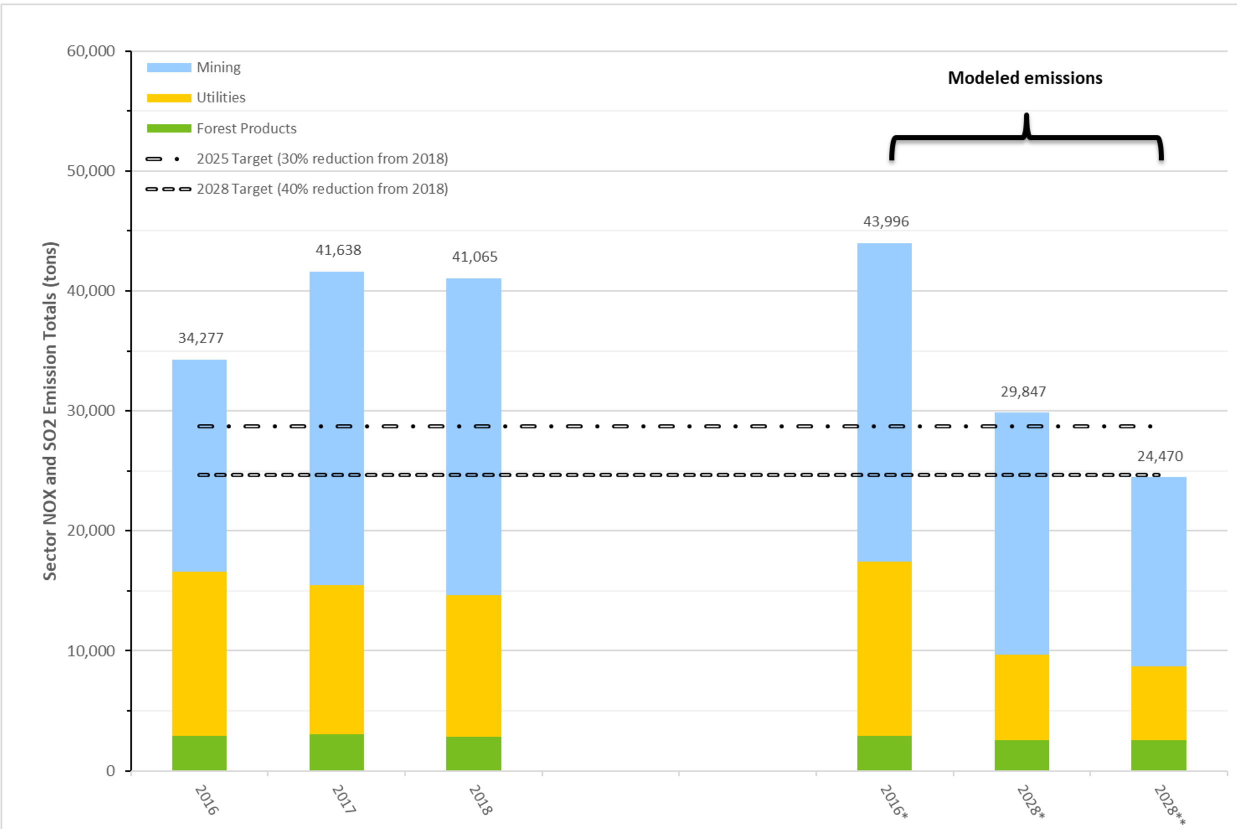
Regarding the 2028* emissions, the MPCA made a specific modification in its modeling analysis to account for the Regional Haze Taconite FIP, discussed previously in Section 1.3, and the estimated emission reductions due to that program as detailed in Section 2.6.1. The 2025 reduction target reflects the emission reduction measures known and included in the modeling analysis for the tracked sources at the time the 2016 model platform was developed. This included the emission reductions expected from the Regional Haze Taconite FIP for U.S. Steel - Minntac, U.S. Steel - Keetac, and United Taconite - Fairlane Plant, but did not include the emission reductions expected from the Regional Haze Taconite FIP for Cleveland Cliffs Minorca Mine and Hibbing Taconite Company (see Table 65 in Section 2.6.2 for a summary of the expected reductions for these facilities).

The 2028** emissions are based on the 2028* emissions, but are adjusted to include:

- The additional NO_X emission reductions expected for Cleveland Cliffs Minorca Mine and Hibbing Taconite Company from the Regional Haze Taconite FIP.

- The additional NO_X emission reductions expected for Hibbing Public Utilities Commission resulting from the NO_X emission limits described earlier in Section 2.5.6.
- Corrections to the over-projected SO_2 emissions for Hibbing Public Utilities Commission.
- See the discussion included in Section 2.6.2 and Table 65 for a direct comparison of the modeled emission change.

Figure 12. Northeast MN Plan - Tracked emissions (2016 - 2018) compared to modeled emissions (2016 & 2028)



As visibility conditions are below the URP line in this implementation period, meaning there isn't a specific reduction needed to reach the URP as in the first implementation period, the MPCA is establishing these emission reduction targets as a backstop. This allows the MPCA to account for emissions from new or modified facilities to ensure that visibility conditions don't worsen and serves as a trigger of sorts that leads to considering/implementing additional, potentially more aggressive, emission reduction measures as part of the 2025 progress report or the 2028 comprehensive update.

2.5.8. Minnesota's long-term strategy

All of the emission reduction strategies that will contribute to meeting the RPGs are documented in this SIP submittal. As discussed previously in Section 2.5.6, Minnesota considered several factors in developing its long-term strategy and has met the requirements of 40 CFR § 51.308(f)(2) as summarized below.

Emission reduction measures necessary to make reasonable progress. MPCA has met the requirements of 40 CFR § 51.308(f)(2)(i) in developing Minnesota's long-term strategy. MPCA evaluated and determined the emission reduction measures needed to make reasonable progress and documented the methodology used in Sections 2.3. Step 3 - Selection of sources for analysis, 2.4. Step 4 -

Characterization of factors for emission control measures, and 2.5. Step 5 - Control measures necessary to make reasonable progress. These emission reduction measures include:

- The completed and upcoming emission unit retirements shown in Table 31 (see Section 2.3.3). Each of these emission unit retirements were accounted for in estimating the projected 2028 emissions included in the MPCA's modeling analysis.
- The utilization of existing effective controls for non-taconite emission units shown in Table 32 (see Section 2.3.5). No additional actions were needed to make these control measures enforceable as the measures have been previously incorporated into the source's Title V operating permit or are required through a different mechanism. The emission rates for these units were accounted for in estimating the projected 2028 emissions included in the MPCA's modeling analysis.
- The additional NO_X emission reductions expected for Hibbing Public Utilities Commission resulting from the NO_X emission limits described earlier in Section 2.5.6. The reductions from the NO_X emission limits were not accounted for in estimating the projected 2028 emissions included in the MPCA's modeling analysis.
- The expected reductions that will be achieved from the full implementation of the Regional Haze Taconite FIP. The MPCA's modeling analysis included the emission reductions expected from the Regional Haze Taconite FIP for U.S. Steel - Minntac, U.S. Steel - Keetac, and United Taconite - Fairlane Plant, but did not include the emission reductions expected from the Regional Haze Taconite FIP for Cleveland Cliffs Minorca Mine and Hibbing Taconite Company (see Table 65 in Section 2.6.2 for a summary of the expected reductions for these facilities).
- The new, non-binding emission reduction targets in the Northeast Minnesota Plan (see Section 2.5.7) for the years associated with the 2025 progress report and the 2028 comprehensive update. These emission reduction targets were not accounted for in estimating the projected 2028 emissions included in the MPCA's modeling analysis but reflect the expected overall emission reductions in Northeast Minnesota from the measures described above.

Details regarding the MPCA's modeling analysis are available in Section 2.6.

Consultation requirements. MPCA has met the requirements of 40 CFR § 51.308(f)(2)(ii) in developing Minnesota's long-term strategy. MPCA has documented the consultation and discussion with various parties done as part of the second regional haze implementation period in Section 2.9. Consultation.

Documenting the technical basis of the long-term strategy. MPCA has met the requirements of 40 CFR § 51.308(f)(2)(iii) in developing Minnesota's long-term strategy. MPCA has documented the technical basis, including the modeling, monitoring, cost, engineering, and emissions information, that was relied on in determining the emission reduction measures that are necessary to make reasonable progress. This information is documented throughout this SIP submittal.

Consideration of additional factors. MPCA has met the requirements of 40 CFR § 51.308(f)(2)(iv) in developing Minnesota's long-term strategy. MPCA has documented how each of the additional factors identified in 40 CFR § 51.308(f)(2)(iv) were considered in Section 2.3.4 as part of the source selection step.

2.6. Step 6 - Regional scale modeling of the long-term strategy (LTS) to set reasonable progress goals (RPGs) for 2028

States with Class I within their borders are required to establish reasonable progress goals (RPGs) for those Class I areas. To set the RPGs, the Regional Haze Rule requires states to project visibility conditions to end of the implementation period that reflect the long-term strategy and other enforceable measures in place.[163] This means that Minnesota must determine the 2028 RPGs for Boundary Waters and Voyageurs, based on the long-term strategy and other enforceable measures described in this document.

The requirement to establish these RPGs is specified in 40 CFR § 51.308(f)(3)(i).

> ***Reasonable progress goals.*** *A state in which a mandatory Class I Federal area is located must establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period as a result of those enforceable emissions limitations, compliance schedules, and other measures required under [40 CFR § 51.308 (f)(2)] that can be fully implemented by the end of the applicable implementation period, as well as the implementation of other requirements of the CAA. The long-term strategy and the reasonable progress goals must provide for an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period.*

U.S. EPA provides additional information regarding the relationship between a state's long-term strategy and the RPGs set for Class I areas located within their borders in its August 2019 Guidance. Briefly, U.S. EPA reiterates that the RPGs are a projected outcome based on the content of the long-term strategy.[164] Meeting the RPGs is not an enforceable requirement of the Regional Haze Rule, but RPGs do provide a useful metric for evaluating progress. The Regional Haze Rule identifies the intended use of the RPGs in 40 CFR § 51.308(f)(3)(iii).

> *The reasonable progress goals established by the State are not directly enforceable but will be considered by the Administrator in evaluating the adequacy of the measures in the implementation plan in providing for reasonable progress towards achieving natural visibility conditions at that area.*

U.S. EPA also clarifies that while states are required to determine the RPGs, there are no requirements in the Regional Haze Rule regarding the method and tools used to do so. U.S. EPA suggests that states will typically project visibility conditions through photochemical air quality modeling.[165] U.S. EPA goes on to identify that many details associated with the U.S. EPA-recommended modeling process for projecting RPGs are explained in further detail within U.S. EPA's November 29, 2018, Modeling Guidance.[166]

MPCA has followed the U.S. EPA modeling guidance for using a photochemical model to estimate future visibility in Boundary Waters and Voyageurs and to establish RPGs. Minnesota provides details of the approach in Appendix A. MPCA's Regional Haze SIP Technical Support Document. This section provides a condensed version of the approach using modeled and monitored air quality data.

2.6.1. Approach to determining Reasonable Progress Goals

Minnesota's modeling platform consists of the U.S. EPA 2016 modeling platform, version 1 with some parts replaced with those provided by LADCO; culminating in a 2016 modeling platform version 1b.[167] The modeling platform consists of meteorology, emissions and other inputs needed to run an air quality

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[163] *See* 40 CFR § 51.308(f)(3)(i).
[164] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 46-47.
[165] *See id.*
[166] *See* U.S. EPA, Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze (Nov. 29, 2018), https://www.epa.gov/sites/default/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf.
[167] *See* U.S. EPA, Technical Support Document, Preparation of Emissions Inventories for the 2016v1 North American Emissions Modeling Platform (Mar. 2021), https://www.epa.gov/sites/default/files/2020-11/documents/2016v1_emismod_tsd_508.pdf.

model. The meteorological inputs were provided by U.S. EPA through its contract with CSRA LLC and distributed through the Intermountain West Data Warehouse.[168]

The comprehensive nationwide emissions inputs were developed by the National Emissions Inventory Collaborative, a group of state, local, tribal, regional, and federal air planning agencies.[169] The regional air planning agencies are the RPOs, such as LADCO. The federal air planning agencies include the U.S. EPA and Federal Land Managers. The U.S. EPA processed, packaged, and distributed the emissions in a model ready format along with job scripts and programs to reformat files for other model applications.[170] Much of the U.S. EPA distributed emissions were retained, but industry and power generation sector emissions were replaced with those processed and distributed by LADCO. Minnesota further processed all emissions inputs, and other miscellaneous inputs, for its own photochemical model application.

The inventory collaborative agreed upon 2016 as the base year to determine reasonable progress for the second implementation period. Comprehensive modeling emissions inventories for regulatory purposes are typically developed on a three-year schedule. The previous full modeling inventory was developed for 2011 which suggests the next two inventories would be scheduled for 2014 and 2017. An evaluation of data available for 2014 indicated it was an atypical year for ozone formation, attainment of the National Ambient Air Quality Standard for ozone being another regulatory purpose for the inventory, but 2016 was promising. At the time, year 2017 would have required an extensive wait for data to become available. The inventory collaborative proceeded to develop the 2016 base year platform and project emissions to 2028 from 2016 for regional haze. Unlike the other RPOs, the Western Regional Air Partnership (WRAP) separately developed a 2014 modeling platform for regional haze.[171]

Meteorology inputs. Meteorology for the 2016 model platform was prepared for input to both the emissions model—some emission sources depend on meteorology for the calculations—and the air quality model using the meteorological model Weather Research and Forecasting (WRF) version 3.8. WRF simulated mesoscale and regional scale atmospheric circulation every hour the entire year 2016 allocated to both a 36km and 12km gridded resolution domain with 35 vertical layers. An evaluation of the meteorological model output compared to measurements determined the WRF simulations reasonably approximate the actual meteorology for regional haze purposes. In the air quality model, meteorology remains constant in the base year and future projected year, 2028.[172]

Emissions inputs. Model-ready emissions inputs for the 2016 model platform were primarily developed with the Sparse Matrix Operator Kernel Emissions (SMOKE) tool version 4.7 with some updates. SMOKE spatially and temporally allocates emissions for input to the air quality model. The air quality model requires hourly emissions allocated to either points, with a longitude and latitude coordinate, or into

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[168] *See* INTERMOUNTAIN WEST DATA WAREHOUSE, https://views.cira.colostate.edu/iwdw/RequestData/Default.aspx (last visited June 23, 2021).

[169] *See* National Emissions Collaborative, *Inventory Collaborative 2016v1 Emissions Modeling Platform,* INTERMOUNTAIN WEST DATA WAREHOUSE (2019), http://views.cira.colostate.edu/wiki/wiki/10202/inventory-collaborative-2016v1-emissions-modeling-platform (last visited June 23, 2022).

[170] *See* Bok Haeng Baek, *National Emission Inventory (NEI) 2016 modeling platform version 1*, UNIVERSITY OF NORTH CAROLINA DATAVERSE (Oct. 31, 2019), https://doi.org/10.15139/S3/KTP4WB (last visited June 23, 2022).

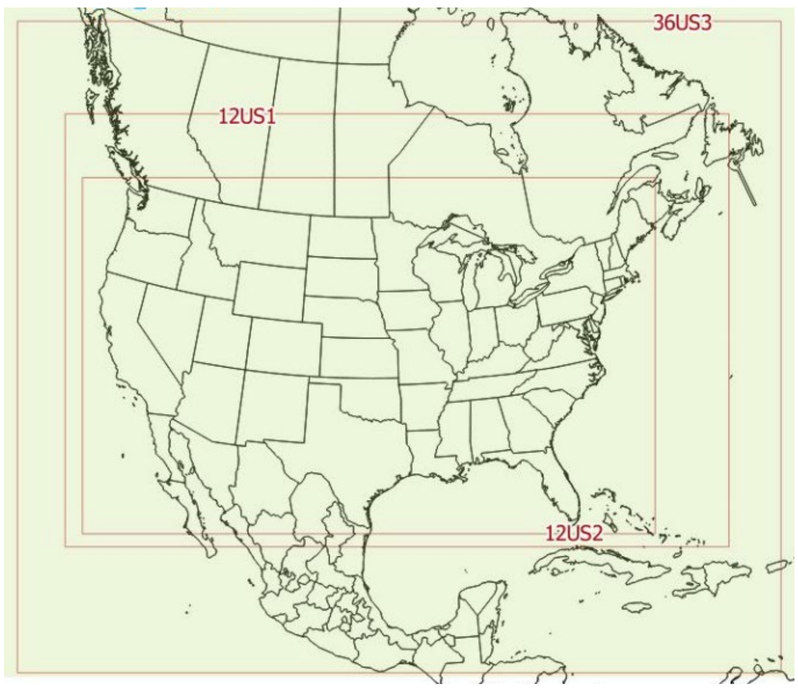
[171] *See* Western Regional Air Partnership & Western States Air Resources Council, WRAP Technical Support System for Regional Haze Planning: Emissions Methods, Results, and References (Sept. 30, 2021), https://views.cira.colostate.edu/tssv2/Docs/WRAP_TSS_emissions_reference_final_20210930.pdf.

[172] *See* U.S. EPA, Meteorological Model Performance for Annual 2016 Simulation WRF v3.8 (July 2019), https://www.epa.gov/sites/default/files/2020-10/documents/met_model_performance-2016_wrf.pdf.

grid cells of a defined size. The grid size chosen depends on the extent of the domain and computational resources.

The U.S. EPA platform domain includes the 48 states of the contiguous United States and parts of Canada and Mexico. There are three grids, two smaller grids nested within a larger grid, as shown in Figure 13. SMOKE derived emissions for two modeling domains comprised of two grid cell sizes. The largest domain “36US3” has 36 km resolution grid cells and the inner “12US1” has 12 km resolution grid cells. For air quality model computations, U.S. EPA extracted a smaller domain “12US2” from “12US1”.

Figure 13. 2016 Model Platform domains



SMOKE also allocates emissions species into those required by the air quality model using speciation profiles by emissions sector. Emissions species prepared for SMOKE include all criteria air pollutants and their precursors; carbon monoxide (CO), lead, sulfur dioxide (SO_2), nitrogen oxides (NOx), Volatile Organic Compounds (VOC), ammonia (NH_3), fine particulate ($PM_{2.5}$) and coarse particulate mass. Some emissions species included are hazardous to health; chlorine (Cl), hydrogen chloride (HCl), benzene, acetaldehyde, formaldehyde, methanol, and naphthalene. How SMOKE allocates emissions species depends on the chemical mechanism applied in the air quality model. Emissions for the 2016 model platform were prepared for the Carbon Bond 6 chemical mechanism.

Emissions were combined into sectors based on the similarity of the techniques used to process the emissions. U.S. EPA and LADCO have assigned abbreviations to identify the iteration of a particular emission sectors development. Table 60 below contains the source of emissions for each sector in the 2016 Model Platform version v1b.

“Sector grouping” refers to the emissions summary tables elsewhere in this document and reflect how emissions were aggregated into files for the air quality model to track the source of the emissions. “Platform sector abbreviation” cross-references the sector grouping with information in the U.S. EPA 2016 platform v1. “Platform sector description” describes the sector abbreviations in the U.S. EPA platform. “Source 2016” and “Source 2028” indicate the iteration and or configuration of the 2016 base and 2028 projection emissions, respectfully. The U.S. EPA “f” represents the modeling platform iteration and the “h” represents the eighth configuration for most sectors of this platform; the “i” being the ninth configuration for airports. The LADCO “v1b” represents substitute emission estimates for the electric power sector (ERTAC version 16.1) and other facilities that emit through stacks. LADCO v1b also includes the 2028 projection for U.S. EPA 2016fi airport emissions, as the future year projection was not available from U.S. EPA. Although the model platform retains the v1b version number, it actually includes LADCO “v1b2” for post-ERTAC 16.1—as of September 2020—shutdowns of additional electric power generating units.

Table 60. Source of emissions for each sector in 2016 Model Platform version 1b

Sector grouping	Platform sector abbreviation	Platform sector description	Source 2016	Source 2028
Agriculture	ag	Livestock and fertilizer application	USEPA 2016fh	USEPA 2028fh
Area	nonpt	Remaining sources due to human population activity data (not emitted through stacks)	USEPA 2016fh	USEPA 2028fh
	othar	Non-road equipment and other nonpoint sectors in Canada and Mexico	USEPA 2016fh	USEPA 2028fh
Dust	afdust_adj	Fugitive dust from roads, building and road construction, agricultural tilling, mining and quarrying (not at industrial facilities)	USEPA 2016fh	USEPA 2028fh
	othafdust_adj	Fugitive dust from roads, building and road construction in Canada	USEPA 2016fh	USEPA 2028fh
	othptdust_adj	Fugitive dust from agricultural tilling in Canada	USEPA 2016fh	USEPA 2028fh
Electric Generating Units (EGU)	ptertac	Electric power generation	LADCO 2016v1b	LADCO 2028v1b2
Fire	ptagfire	Agricultural fires	USEPA 2016fh	USEPA 2016fh
	ptfire_othna	Wild and prescribed fires in Canada & Mexico	USEPA 2016fh	USEPA 2016fh
	ptfire	Wild and prescribed fires	USEPA 2016fh	USEPA 2016fh
Industry	ptmntaconite	"Typical" taconite mine emissions that account for facilities/units not operating in 2016 in Minnesota	LADCO 2016v1b	LADCO 2028v1b
	ptnonertac	Remaining units that emit through stacks not covered in other sectors	LADCO 2016v1b	LADCO 2028v1b
	othpt	Point sources from Canada and Mexico	USEPA 2016fh	USEPA 2028fh
Natural	beis	Natural vegetation	USEPA 2016fh	USEPA 2016fh
	seasalt	Ocean salt	Calculated_2016	Calculated_2016

Sector grouping	Platform sector abbreviation	Platform sector description	Source 2016	Source 2028
Off-Road	airports	Aircraft up to 3,000 feet elevation and ground support equipment	USEPA 2016fi	LADCO 2028v1b
	cmv_c1c2	Category 1 and 2 commercial marine vessels in State and Federal waters and non-US waters	USEPA 2016fh	USEPA 2028fh
	cmv_c3	Category 3 commercial marine vessels	USEPA 2016fh	USEPA 2028fh
	nonroad	Vehicles that do not travel by road, excluding commercial marine, rail, and aircraft. Includes recreational vehicles, pleasure craft, construction, agricultural, mining, and lawn and garden equipment.	USEPA 2016fh	USEPA 2028fh
	rail	Line haul rail locomotives, including freight, and commuter rail	USEPA 2016fh	USEPA 2028fh
Oil/Gas	np_oilgas	Oil and gas upstream activities of exploration and drilling wells, and equipment to extract the product and deliver it to a central collection point or processing facility. Includes separators, dehydrators, storage tanks, and compressor engines.	USEPA 2016fh	USEPA 2028fh
	pt_oilgas	Oil and gas upstream exploration, production, pipeline-transportation, and distribution emissions sources, both onshore and offshore.	USEPA 2016fh	USEPA 2028fh
On-Road	onroad	Gasoline and diesel powered vehicles, moving and non-moving, that travel on roads. Includes refueling, exhaust, extended idle, auxiliary power, evaporation, permeation, and break and tire wear. Excludes California	USEPA 2016fh	USEPA 2028fh
	onroad_ca_adj	Gasoline and diesel powered vehicles that travel on roads for California only	USEPA 2016fh	USEPA 2028fh
	onroad_can	Gasoline and diesel powered vehicles that travel on roads in Canada	USEPA 2016fh	USEPA 2028fh
	onroad_mex	Gasoline and diesel powered vehicles that travel on roads in Mexico	USEPA 2016fh	USEPA 2028fh
Residential Wood Combustion (RWC)	rwc	Residential wood combustion	USEPA 2016fh	USEPA 2028fh

Explore emissions inputs for modeling Minnesota 2028 interim visibility goals

This interactive tool shows the emissions input to the atmospheric chemistry model to develop our visibility goals at Minnesota Class I areas.

Minnesota has developed an interactive online tool accessible from the Pollution Control Agency website (click on icon above) that allows the user to explore the base year 2016 emissions and the change in emissions from the 2016 to the 2028 projection emissions.[173] The tool provides spatial maps showing the gradient of emissions across the entire domain and by region and provides graphs of the emissions by pollutant and by sector grouping. The tool provides the same emissions as a monthly profile. Finally, the tool examines 2016 and 2028 emissions by individual Minnesota facilities that make up about 80 percent of emissions from all facilities in the State. Hovering over various places in the tool reveal additional information, for example in the Minnesota facilities tab hovering over an up or down arrow may provide known reasons for a change in emissions from the base year to the future year.

Base year inventory - 2016. For the most part, base year inventories are developed by each individual state. These are essentially the same inventories states submit to the U.S. EPA for the National Emissions Inventory (NEI). For some sectors, methods initially available to states for inventory development were inadequate for air quality modeling. For these sectors, the national emissions inventory collaborative is invaluable to support improvement of state-developed inventories where the other methodology, insufficient for modeling purposes, was used. For example, it is important to have accurate ammonia emissions because ammonia combines with sulfuric and nitric acid to form aerosol sulfate and nitrate, significant components of $PM_{2.5}$ and of visibility impairment. Also, states do not create inventories for biogenic sources, so these inventories had to be created for modeling purposes. The collaborative also limited the variation in the emissions characterization of a state among the RPO in which it is a member and other RPOs (which commonly occurred during the first implementation period)

LADCO prepared both an “actual” and “typical” emissions inventory for Minnesota. The actual emissions inventory was only used for evaluating air quality model performance. The typical emissions inventory was used for establishing RPGs and for the contribution assessment described in Section 2.2 of this document. The only difference between the actual and typical emissions inventories involves the characterization of emissions from the taconite facilities in Minnesota.

As described in Section 1.3 of this document, U.S. EPA during the first implementation period promulgated a FIP for taconite facilities subject-to-BART. Some of these facilities were either not operating or operating at reduced production in 2016. In order to simulate the impact of the control measures in the FIP this implementation period, Minnesota substituted the 2016 emissions with emissions from 2017; the “typical” case. This allowed Minnesota to represent the emissions changes in 2028.

Table 61 below contains 2016 typical emissions for 12US2 domain in tons per year. Emissions are back-calculated from the air quality modeling files used in this analysis. The lumped model species are not

173 MPCA Data Services, REGIONAL AIR EMISSIONS 2016 PLATFORM (April 26, 2022), https://public.tableau.com/app/profile/mpca.data.services/viz/Regionalairemissions2016platform/Viewbysector#1 (last visited June 23, 2022).

constant but can vary depending on the speciation profile. Emission total differences of VOC can vary by sector as large as 10%, or higher, between totals calculated before and after speciation.

Table 61. 2016 base year typical annual emissions in tons by region and sector

Contiguous United States							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Agriculture		3,420,000					176,000
Area	2,650,000	78,900	713,000	572,000	465,000	139,000	3,510,000
Dust				7,200,000	1,000,000		
EGU	613,000	26,300	1,290,000	173,000	132,000	1,520,000	37,700
Industry	1,460,000	64,500	977,000	398,000	256,000	691,000	744,000
Oil/gas	925,000	4,350	907,000	24,200	23,900	52,200	3,180,000
On-road	19,100,000	89,300	3,410,000	217,000	106,000	26,000	1,930,000
Off-road	11,100,000	2,220	1,940,000	138,000	130,000	20,900	1,300,000
RWC	2,130,000	15,600	31,500	320,000	319,000	7,750	305,000
Fire	14,000,000	291,000	238,000	1,500,000	1,260,000	115,000	2,530,000
Natural	7,120,000		1,470,000				40,100,000
Canada							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Area	2,100,000	3,600	265,000	232,000	192,000	13,900	622,000
Dust				714,000	148,000		
Industry	511,000	352,000	233,000	63,800	24,800	511,000	373,000
On-road	1,180,000	5,200	273,000	17,800	9,550	1,210	112,000
Fire	346,000	5,730	7,500	37,700	31,900	3,430	60,400
Natural	1,240,000		114,000				7,660,000
Mexico							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Area	198,000	171,000	183,000	92,600	43,700	6,170	418,000
Industry	170,000	4,560	365,000	63,600	49,600	428,000	60,400
On-road	1,590,000	2,430	389,000	12,900	9,080	5,260	158,000
Fire	291,000	5,660	12,900	33,200	28,100	2,040	91,400
Natural	1,120,000		145,000				4,960,000
Offshore							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Oil/gas	50,900	18.0	49,500	689	687	699	59,400
Off-road	60,200	365	523,000	20,500	18,900	106,000	29,000

Future year inventory - 2028. The national emissions inventory collaborative used methods specific to the type of emissions source to project emissions to 2028. Some methods involved projection models. For example, LADCO incorporated electric generating unit emissions projected by the Eastern Regional

Technical Advisory Committee (ERTAC) model version 16.1.[174] Other sectors were projected using forecast information from sector organizations and other methodologies.

Taconite FIP emissions for the projected typical emissions inventory. LADCO prepared a projected "typical" emissions inventory for Minnesota by incorporating the MPCA-provided emissions projections for taconite facilities that apply FIP limits from the first implementation period.

The taconite companies provided the MPCA with a full year of Continuous Emission Monitoring System (CEMS) data of NO_X and SO_2 emission rates in pounds per hour and heat input rates in Million British Thermal Units (MMBtu) per hour. U.S. Steel - Minntac provided CEMS data for 2016 while U.S. Steel - Keetac and United Taconite provided CEMS data for 2017. The MPCA estimated the emissions reduction needed to meet the FIP limit by using the CEMS data to convert the NO_X and SO_2 emissions and associated heat input into emission rates that allowed for a comparison to what would become the FIP limit.

To compare heat input and emissions data from hourly CEMS readings with the current FIP limits, the MPCA converted the hourly CEMS data into the units equivalent to those used for the FIP limits, a 720-hour rolling average NO_X emission rate in lb/MMBtu and a 720-hour rolling average SO_2 emission rate in lb/hour. The needed reduction to meet the FIP was calculated for each hour, with the assumption the heat input rate would stay the same in future. The calculation was done for all 8760 hours in the year (8784 hours in the 2016 leap year) to obtain annual emissions for the year, which then allowed for estimating the average annual percent reduction, shown in Table 62.

Table 62. Estimated average annual percent reduction at taconite facilities due to FIP

Facility name[175]	Unit name	NO_X % change	SO_2 % change
U.S. Steel - Minntac	Line 3	-36	0
	Line 4	-33	0
	Line 5	-34	0
	Line 6	-33	0
	Line 7	-37	0
U.S. Steel - Keetac	Grate Kiln	-73	0
United Taconite LLC - Fairlane Plant	Line 1 Pellet Induration	-2	0
	Line 2 Pellet Induration	-23	0

MPCA considers the taconite emissions projection fairly conservative, post-FIP controls resulting in lower emissions, for a few reasons:

- The calculations determine the hourly reduction needed to meet the applicable limit.
- The hourly reduction is applied only to the specific hour of emissions, while keeping the heat input static.

[174] *See* U.S. EPA, Eastern Regional Technical Advisory Committee (ERTAC) Electricity Generating Unit Emission Projection Tool (2015 EIC) (Nov. 16, 2021), https://www.epa.gov/air-emissions-inventories/eastern-regional-technical-advisory-committee-ertac-electricity (last visited June 23, 2022).

[175] *U.S. Steel - Minntac percent reduction is for 2016 to 2028, U.S. Steel - Keetac percent reduction is for 2017 to 2028, and United Taconite - Fairlane Plant reduction is for 2017 to 2028.*

- Some hours of the year didn't need a percent reduction to meet the FIP limit and were retained at the measured emission level. Low-NO_X burners presumably would provide additional control during these times.

At the time the 2016 modeling platform version v1b was developed, the data was not available for Minnesota to apply this method to all taconite facilities in the FIP. Taconite facilities with no adjustment to the future year modeling inventory are Hibbing Taconite Company (~54% reduction in NO_X) and Cleveland-Cliffs Minorca Mine (~65% reduction in NO_X).

Table 63 below contains all sector 2028 emissions, projected from 2016 typical, for 12US2 domain in tons per year. Emissions are back-calculated from the air quality modeling files used in this analysis. The lumped model species are not constant but can vary depending on the speciation profile. Emission total differences of VOC can vary by sector as large as 10%, or higher, between totals calculated before and after speciation.

Table 63. 2028 future year annual emissions in tons by region and sector

Contiguous United States							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Agriculture		3,580,000					186,000
Area	2,680,000	80,000	711,000	596,000	486,000	107,000	3,590,000
Dust				7,280,000	1,020,000		
EGU	728,000	57,700	898,000	156,000	130,000	913,000	40,200
Industry	1,480,000	64,700	966,000	403,000	261,000	601,000	745,000
Oil/gas	958,000	4,410	911,000	29,300	28,800	73,700	3,800,000
On-road	9,930,000	78,400	1,150,000	168,000	49,700	10,400	866,000
Off-road	11,700,000	2,470	1,380,000	84,000	78,200	39,600	1,000,000
RWC	2,040,000	14,700	32,300	302,000	302,000	6,830	292,000
Fire	14,000,000	291,000	238,000	1,500,000	1,260,000	115,000	2,530,000
Natural	7,120,000		1,470,000				40,100,000
Canada							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Area	2,040,000	3,440	190,000	219,000	171,000	13,500	637,000
Dust				837,000	169,000		
Industry	568,000	491,000	199,000	55,200	27,800	372,000	369,000
On-road	930,000	4,110	115,000	18,600	6,600	535	46,700
Fire	346,000	5,730	7,500	37,700	31,900	3,430	60,400
Natural	1,240,000		114,000				7,660,000
Mexico							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Area	229,000	169,000	212,000	96,900	47,100	6,570	509,000
Industry	215,000	6,580	420,000	80,900	61,700	390,000	87,900
On-road	1,410,000	3,260	346,000	15,400	10,200	7,180	164,000
Fire	291,000	5,660	12,900	33,200	28,100	2,040	91,400
Natural	1,120,000		145,000				4,960,000

Offshore							
Sector	**CO**	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
Oil/gas	50,900	16.9	49,400	692	690	819	59,600
Off-road	79,400	335	496,000	18,800	17,400	51,300	38,100

Air Quality modeling. U.S. EPA and LADCO processed emissions through the SMOKE emissions model for input to the Community Multiscale Air Quality (CMAQ) model. Minnesota processed the CMAQ files for input to the Comprehensive Air quality Model with eXtensions (CAMx) model, which was used to develop the RPGs. Inputs were prepared for the 12US2 Conus domain.[176]

CAMx simulates atmospheric and surface processes affecting the transport, chemical transformation and deposition of air pollutants and their precursors. The model allows for tracking the original source of particulate species by geographic region or source category with the module Particulate Source Apportionment Technology (PSAT). CAMx is a Eulerian model that computes a numerical solution on a fixed grid. Minnesota used CAMx version 7.0 to develop the RPGs.

Although emissions and meteorology were generated for every hour and allocated to both 36km grids over the U.S. EPA 12US1 Domain and 12km grids over the U.S. EPA 12US2, Minnesota utilized inputs only for the 12US2 domain. This domain was agreed upon by all the RPOs as the basic domain from which to model. U.S. EPA used the 12US1 domain to create boundary conditions for the 12US2 domain.

CAMx requires other inputs in addition to emissions and meteorology that were developed by U.S. EPA. Initial and boundary conditions were distributed through the Intermountain West Data Warehouse. Land use, and ozone column and photolysis rates for photochemical mechanisms were included in the 2016 model platform package distributed by U.S. EPA.

Initial Conditions. Air quality models require an initial emissions file to input as a starting point from which to model. Effects of the initial condition concentrations on modeling results are mitigated by simulating a ramp-up period of several days prior to the beginning of the desired model results.

Boundary Conditions. U.S. EPA developed boundary condition files generated with a hemispheric version of CMAQ that incorporated updated global emissions. Output from a larger regional or global modeling simulation feeds hourly lateral boundary conditions to the domain being modeled. Sources outside the modeling domain can have an important influence on concentrations within the domain modeled with the air quality model.

Air quality model performance - 2016 actual emissions. Minnesota evaluated model performance for the $PM_{2.5}$ component species against IMPROVE and Continuous Speciated Network (CSN) monitor data in Minnesota and surrounding states. Particular attention was placed on the 20 percent most impaired and 20 percent clearest days in Boundary Waters and Voyageurs. U.S. EPA guidance recommends considering various statistical assessments and other techniques of model versus observed pairs when conducting a performance evaluation. These techniques include spatial plots, time series plots and qualitative descriptions. Focus for the statistical assessment is on mean fractional bias and error.

The statistical evaluation was done for 24-hour averaging times for prediction/observation pairs. The predictions are extracted from model simulation with the “actual” 2016 emissions. The model performance results are described in detail in Appendix A. MPCA’s Regional Haze SIP Technical Support Document.

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[176] *See* COMPREHENSIVE AIR QUALITY MODEL, https://www.camx.com/ (last visited June 23, 2022).

Relative Response Factors. Minnesota used CAMx model with the inputs described above to simulate the future visibility conditions that will result from future emissions estimates. U.S. EPA guidelines require model simulations of emissions from a “base” or known, year (i.e., 2016) representing the baseline period and from a year in the future (i.e., 2028). The model results are used to estimate the air concentration change from base year to future year. These air concentration changes are in the form of ratios of the future year air concentrations to the base year concentrations predicted near a monitor location and averaged over the same 20 percent most impaired and 20 percent clearest days in the base year that were used to establish baseline visibility conditions in Section 2.1. A ratio is developed for each species comprising $PM_{2.5}$ (sulfate, nitrate, organic carbon, elemental carbon, fine soil [≤2.5 µm diameter], and coarse particulate matter [>2.5 µm, but ≤10 µm diameter]). The ratio, called a Relative Response Factor (RRF), is calculated as follows:

$$RRF_{[SO4]} = \text{Modeled Future Mean}_{[SO4]} / \text{Modeled Base Year Mean}_{[SO4]}$$

Where: RRF is the relative response factor (unitless);

Future Mean and Base Year Mean are the modeled base year (2016) and the future year (2028) concentrations at the Class I area monitor location averaged for the 20 percent most impaired days (and 20 percent clearest days) as determined by the base year (2016) monitor data; and

The same equation above for sulfate is also used for nitrate, organic carbon, elemental carbon, fine soil, and coarse particulate matter.

Applying the RRFs to baseline monitoring conditions, for each species comprising $PM_{2.5}$, provides the estimate of future visibility conditions in Section 2.6.2 below.

2.6.2. Reasonable Progress Goals for Boundary Waters and Voyageurs

Recognizing the intense resources required to conduct modeling analyses of this nature, U.S. EPA guidelines for regional haze do not suggest modeling the multiple years comprising the 5-year baseline period (2014 - 2018), but discuss modeling one full year (i.e., 2016) as a “logical goal”. The methodology in the U.S. EPA guidelines attempts to take into account the year-to-year variability of the meteorology in the monitored baseline. The middle year (2016) will have more weight due to the fact that the 2016 emissions and meteorology are used in the modeling to develop the RRF applied to the baseline conditions in Section 2.1. Step 1 - Ambient data analysis. This application of the model results intends to balance the resource limitations of conducting multiple years of modeling, and to “help reduce the impact of possible over-or under-estimations by the dispersion model due to emissions, meteorology, or general selection of other model input parameters”.[177]

- Multiply each species specific RRF by the corresponding measured species concentration for all of the 20 percent worst (and 20 percent best) days over the 5-year baseline period (e.g., future sulfate is calculated as follows $[SO_4]$future = $RRF_{(SO4)}$ multiplied by $[SO_4]$baseline (daily value);
- Estimate extinction coefficient for each of the 20 percent most impaired (and 20 percent clearest) days using the IMPROVE equation, and convert to deciviews (detailed in Section 2.1); and
- Calculate the average future year deciview for the 20 percent most impaired (and 20 percent clearest) days.

[177] *See U.S. EPA, Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze (Nov. 29, 2018).*

- Calculate the arithmetic mean deciview value for the 20 percent most impaired and clearest visibility values for each year in the baseline period; and
- Average the resulting 5-year mean deciview values (for the 20 percent most impaired, and for the 20 percent clearest).

MPCA has set the 2028 RPGs for Boundary Waters and Voyageurs at the deciview levels, 13.4 dv for Boundary Waters and 13.6 dv for Voyageurs, shown in Table 64. The 2028 model projection for the clearest days, 4.5 dv for Boundary Waters and 5.3 dv for Voyageurs, ensures "no degradation" from baseline visibility, 6.5 dv for Boundary Waters and 7.2 dv for Voyageurs (see Section 2.7 for more details).

Table 64. Reasonable progress goals (RPG) at Boundary Waters and Voyageurs

Intermediate goal year	Boundary Waters		Voyageurs	
	Most impaired RPG	Clearest[178] No degradation	Most impaired RPG	Clearest No degradation
Round 1: 2018 (dv)	17.2	6.6	17.5	7.2
Round 2: 2028 (dv)	13.4	4.5	13.6	5.3

Factors impacting the RPG. Not all measures in the long-term strategy are reflected in the RPGs because they were not available at the time the 2016 model platform was developed. Table 65 lists all the facilities and emission units MPCA considered for the long-term strategy and how they are reflected in the emissions projections.

All the emission unit retirements at the electric generation facilities are included in the long-term strategy. However, the ERTAC emissions projection model shifts power generation to other emission units, including at facilities with emission unit retirements.

- Xcel Energy - Sherburne units 1 and 2 are retired in the modeling, but emissions increase at unit 3 which is scheduled to retire in 2030.
- Minnesota Power - Boswell Energy Center units 1 and 2 are retired in the modeling, but emissions increase at units 3 and 4.
- Hibbing Public Utilities Commission is not scheduled to retire, but there are NO_X emission reductions scheduled for implementation via emission limits. But ERTAC increases emissions at three of the units considered in the four-factor analysis.

Measures that did not make it into the modeling, and therefore are not reflected in the RPG are:

- Hibbing Taconite Company requirements in the Taconite FIP for the first implementation period.
- Cleveland Cliffs Minorca Mine requirements in the Taconite FIP for the first implementation period.

[178] *In the first implementation period, the 2018 projection was 0.1 dv above the goal of no degradation, 6.5 dv*

Table 65. Long term strategy measures reflected in the RPGs for Boundary Waters and Voyageurs

Facility name	Emission unit	Action	Reflected in RPG	Modeled emission change			
				ΔNO_X		ΔSO_2	
				Tons	%	Tons	%
American Crystal Sugar - Crookston	Boiler 1	-	-	-	-	-	-
	Boiler 2	-	-	-	-	-	-
	Boiler 3	-	-	-	-	-	-
American Crystal Sugar - East Grand Forks	Boiler 1	-	-	-	-	-	-
	Boiler 2	-	-	-	-	-	-
Boise White Paper	Recovery Furnace	-	-	-	-	-	-
	Boiler 1	-	-	-	-	-	-
	Boiler 2	-	-	-	-	-	-
Cleveland Cliffs Minorca Mine Inc.	Indurating Machine	Low NO_X burners	No	-2,102	-65%	-	-
Hibbing Public Utilities Commission	Boiler No. 1A	ERTAC	Yes	+6	+4%	+198	+133%
	Boiler No. 2A	ERTAC	Yes	+125	+315%	+311	+830%
	Boiler No. 3A	ERTAC	Yes	-30	-15%	+179	+106%
	Wood Fired Boiler	-	-	-	-	-	-
Hibbing Taconite Company	Indurating Furnace Line 1	Low NO_X burners	No	-730	-61%	-	-
	Indurating Furnace Line 2	Low NO_X burners	No	-846	-48%	-	-
	Indurating Furnace Line 3	Low NO_X burners	No	-731	-54%	-	-
Minnesota Power - Boswell Energy Center	Unit 1	Retired 2018	Yes	-540	-100%	-1,560	-100%
	Unit 2	Retired 2018	Yes	-456	-100%	-1,391	-100%
	Unit 3	ERTAC	Yes	+88	+12%	+17	+12%
	Unit 4	ERTAC	Yes	+265	+10%	+56	+10%
Minnesota Power - Taconite Harbor Energy	Boiler 1	Retirement 2023	Yes	-219	-100%	-525	-100%
	Boiler 2	Retirement 2023	Yes	-187	-100%	-407	-100%
Northshore Mining - Silver Bay	Power Boiler 1	Idled to 2031	Yes	-377	-100%	-609	-100%
	Power Boiler 2	Idled to 2031	Yes	-1,011	-100%	-782	-100%
	Furnace 11	-	-	-	-	-	-
	Furnace 12	-	-	-	-	-	-
Sappi Cloquet LLC	Power Boiler #9	-	-	-	-	-	-
	Recovery Boiler #10	-	-	-	-	-	-
Southern Minnesota Beet Sugar Coop	Boiler 1	-	-	-	-	-	-

Facility name	Emission unit	Action	Reflected in RPG	Modeled emission change			
				ΔNO_X		ΔSO_2	
				Tons	%	Tons	%
United Taconite LLC - Fairlane Plant	Line 1 Pellet Induration	Low NO_X burners	Yes	-22	-2%	-	-
	Line 2 Pellet Induration	Low NO_X burners	Yes	-549	-23%	-	-
US Steel Corporation - Keetac	Grate Kiln	Low NO_X burners	Yes	-3,654	-73%	-	-
US Steel Corporation - Minntac	Line 3 Rotary Kiln	Low NO_X burners	Yes	-405	-36%	-	-
	Line 4 Rotary Kiln	Low NO_X burners	Yes	-630	-33%	-	-
	Line 5 Rotary Kiln	Low NO_X burners	Yes	-410	-34%	-	-
	Line 6 Rotary Kiln	Low NO_X burners	Yes	-337	-33%	-	-
	Line 7 Rotary Kiln	Low NO_X burners	Yes	-398	-37%	-	-
Virginia Department of Public Utilities	Boiler 7	Retirement 2025	Yes	-23	-100%	-39	-100%
	Boiler 9	Retirement 2021	Yes	-214	-100%	-247	-100%
	Boiler 11	-	-	-	-	-	-
Xcel Energy - Allen S. King	Boiler 1	Retirement 2028	Yes	-1,380	-100%	-1,505	-100%
Xcel Energy - Sherburne	Unit 1	Retirement 2026	Yes	-3,057	-100%	-451	-100%
	Unit 2	Retirement 2023	Yes	-1,929	-100%	-306	-100%
	Unit 3	Retirement 2030 / ERTAC	No / Yes	+525	+15%	+1,168	+15%
Total (Northeast Minnesota facilities)				-13,387	-	-4,799	-
Total (all facilities)				-19,228	-	-5,893	-

Overall, MPCA believes the RPGs are a conservative estimate of the visibility improvements due to Minnesota's long-term strategy for the second regional haze implementation period. The modeling analysis, and therefore the RPGs, do not account for all the emission reductions expected from Minnesota's long-term strategy suggesting that visibility conditions will improve more than predicted.

2.7. Step 7 - Progress, degradation, and uniform rate of progress (URP) glidepath checks

After states with Class I areas within their borders establish RPGs for their Class I area(s), the Regional Haze Rule requires a comparison of the RPGs to the baseline period visibility conditions and to the uniform rate of progress (URP) glidepath.[179] This means that Minnesota must provide this comparison for the 2028 RPGs for Boundary Waters and Voyageurs.

In its August 2019 Guidance, U.S. EPA summarizes the needed information for the progress, degradation, and URP glidepath checks that states must provide for Class I areas within their borders:[180]

- Demonstrate that there will be an improvement on the 20% most impaired days in 2028 compared to 2000-2004 conditions.
- Demonstrate that there will be no degradation on the 20% clearest days in 2028 compared to 2000-2004 conditions.
- Determine the URP that would achieve natural conditions in 2064 (may be adjusted for certain international impacts and wildland prescribed fires subject to U.S. EPA approval).
- Compare the 2028 RPGs for the most impaired days to the 2028 point on the URP glidepath (with additional demonstrations required if the RPG is above the glidepath).

Minnesota Class I areas show marked improvement on the 20% most impaired days and show no degradation on the 20% clearest days in 2028 compared to 2000-2004 conditions. Table 66 shows the values at each milestone and placement of the 2028 RPGs on the glidepath diagrams below for Boundary Waters and Voyageurs illustrate the marked progress.

Table 66. Progress, degradation, and glidepath checks at Boundary Waters and Voyageurs

Days	Milestone	Boundary Waters	Voyageurs
Most impaired	2004 Baseline (dv)	18.5	17.9
	2028 Projection (dv)	13.4	13.6
	Progress (2028 - 2004) (dv)	-5.1	-4.3
	Uniform rate of progress (dv)	14.7	14.5
	Glidepath check (2028 - URP) (dv)	-1.3	-0.9
Clearest	2004 Baseline (dv)	6.5	7.2
	2028 Projection (dv)	4.5	5.3
	No degradation check (2028 - 2004) (dv)	-2.0	-1.9

Achieving natural conditions in 2064 looks promising even without adjusting for international impacts and wildland prescribed fires. Should those adjustments be made in future implementation periods, meeting natural conditions might begin to occur much earlier than 2064. While Minnesota does not seek U.S. EPA approval to adjust the 2064 end goal this implementation period, readily available information described in Section 2.1. Step 1 - Ambient data analysis suggests an earlier end point.

The 2028 RPGs for the most impaired days at Boundary Waters and Voyageurs are below the 2028 point on the URP glidepath. No additional demonstrations are required.

[179] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 48.
[180] See *id. at 6.*

Figure 14. Progress, degradation, and glidepath checks at Boundary Waters

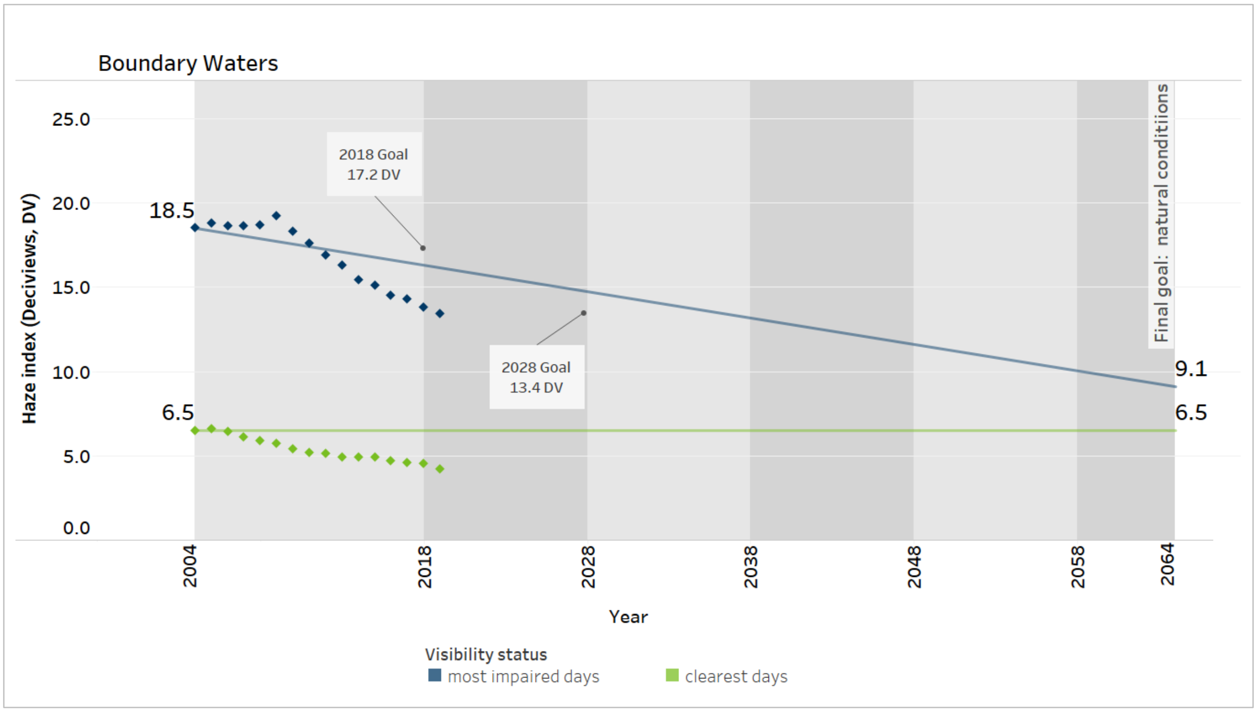
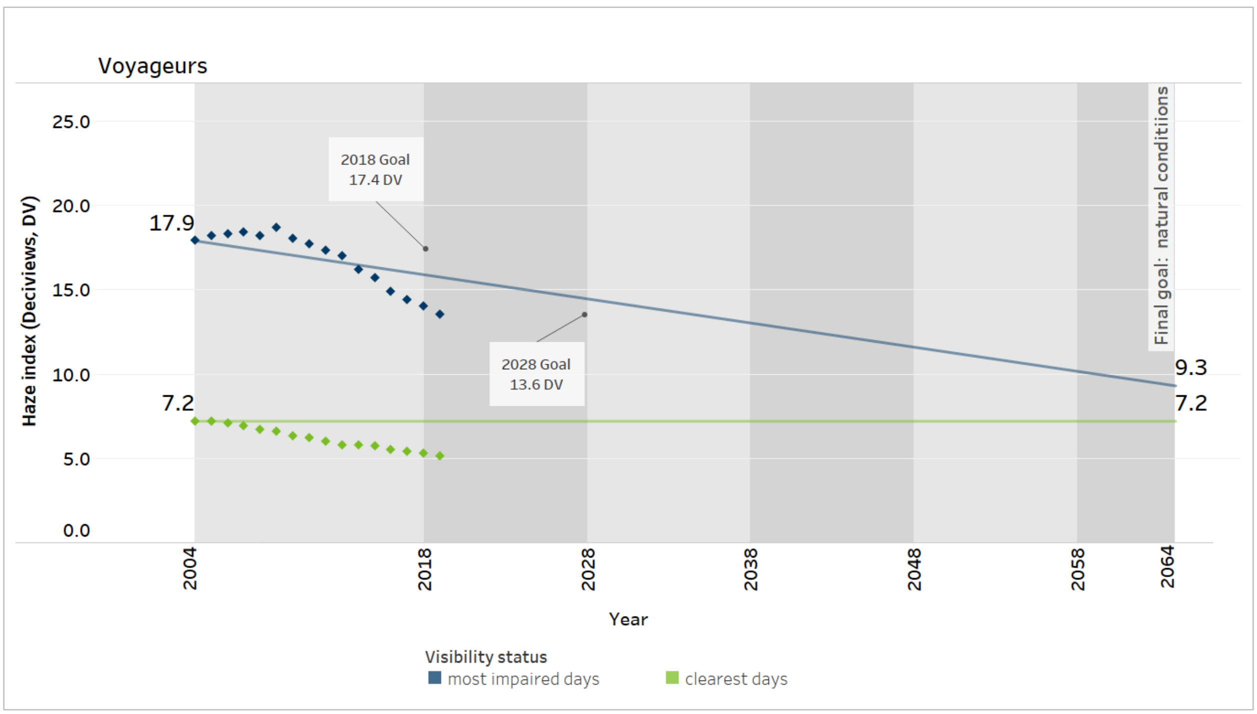


Figure 15. Progress, degradation, and glidepath checks at Voyageurs



2.8. Step 8 - Additional requirements for SIPs

Beyond the information discussed in previous sections, this section provides additional information necessary to ensure that other requirements of the Regional Haze Rule are met. All states, including those without Class I areas, are required to address the requirements of the Regional Haze Rule regarding reasonably attributable visibility impairment, progress report requirements, a monitoring strategy, and other elements. Each of these requirements are discussed in further detail in the following sections.

2.8.1. Consultation and discussion with other parties

The Regional Haze Rule requires states consult with other states that have emissions that are reasonably anticipated to contribute to visibility impairment in the same Class I area(s), in order to develop coordinated emission management strategies, as specified in 40 CFR § 51.308(f)(2)(ii). Consultation between states and the Federal Land Managers (FLMs) is also required as specified in 40 CFR § 51.308(i).

Details of consultation and discussion with various parties are discussed in further detail in Section 2.9. Consultation.

2.8.2. Reasonably attributable visibility impairment (RAVI)

The Regional Haze Rule requires that if U.S. EPA or a Federal Land Manager (FLM) advises a state that additional monitoring is needed to assess RAVI is needed in addition to the monitoring currently being conducted, that state must include in the SIP revision an appropriate strategy to evaluate RAVI by visual observation or other appropriate monitoring techniques. This requirement is specified in 40 CFR § 51.308(f)(4).

> *If the Administrator, Regional Administrator, or the affected Federal Land Manager has advised a State of a need for additional monitoring to assess reasonably attributable visibility impairment at the mandatory Class I Federal area in addition to the monitoring currently being conducted, the State must include in the plan revision an appropriate strategy for evaluating reasonably attributable visibility impairment in the mandatory Class I Federal area by visual observation or other appropriate monitoring techniques.*

During the first regional haze implementation period, Xcel Energy - Sherburne Generating Plant was certified as a source of RAVI in Minnesota and became subject to a FIP that established emission limitations as described in Section 1.4.

Minnesota has not received such a notice from either U.S. EPA or the FLMs for the Boundary Waters or Voyageurs for the second regional haze implementation period.

2.8.3. Progress report elements

The Regional Haze Rule requires states to address the progress report requirements within each Regional Haze SIP revision, so that the revision will also serve as a progress report. This requirement is specified in 40 CFR § 51.308(f)(5).

> *So that the plan revision will serve also as a progress report, the State must address in the plan revision the requirements of [40 CFR §51.308(g)(1)-(5)]. However, the period to be addressed for these elements shall be the period since the most recent progress report.*

The progress report elements are discussed in further detail in Section 2.10. Five-year progress report.

2.8.4. Monitoring strategy

The Regional Haze Rule requires states to provide a strategy for monitoring ambient visibility conditions that is representative of all Class I areas within their borders. This requirement is specified in 40 CFR § 51.308(f)(6).

> ***Monitoring strategy and other implementation plan requirements.*** *The State must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the State. Compliance with this requirement may be met through participation in the Interagency Monitoring of Protected Visual Environments network. The implementation plan must also provide for the following:*
>
> - *(i) The establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals to address regional haze for all mandatory Class I Federal areas within the State are being achieved.*
> - *(ii) Procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas both within and outside the State.*
> - *(iii) For a State with no mandatory Class I Federal areas, procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas in other States.*
> - *(iv) The implementation plan must provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the State. To the extent possible, the State should report visibility monitoring data electronically.*
> - *(v) A statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for the most recent year for which data are available, and estimates of future projected emissions. The State must also include a commitment to update the inventory periodically.*
> - *(vi) Other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility.*

As stated in the requirement, participation in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network provides compliance with the requirement. Additionally in its August 2019 Guidance, U.S. EPA recommends that all states with Class I areas confirm their participation in the IMPROVE monitoring program with respect to 40 CFR § 51.308(f)(6)(i) through (iv).[181]

Minnesota continues to rely upon participation in the IMPROVE program to meet its monitoring strategy requirements with no modifications to the strategy determined necessary at this time.

The IMPROVE Aerosol Network is a cooperative air quality monitoring effort between federal land managers; regional, state, and tribal air agencies; and the U.S. EPA. The program was established in 1985 to aid in developing Federal and State implementation plans for the protection of visibility in Class I areas. The network began with 42 sites at or near Class I areas. At the time of promulgation of the Regional Haze Rule in 1999, there were 80 monitors. In 2000 and 2001, an additional 30 sites were added to Class I areas, and 34 to non-Class I areas. (IMPROVE monitors operated outside of Class I areas

[181] *See U.S. EPA, Aug. 2019 EPA Guidance, supra, at 55.*

are “Protocol” monitors, operated for FLMs, states, and tribes). The IMPROVE network presently comprises 175 monitoring sites nationally.

The objectives of the IMPROVE network are:[182]

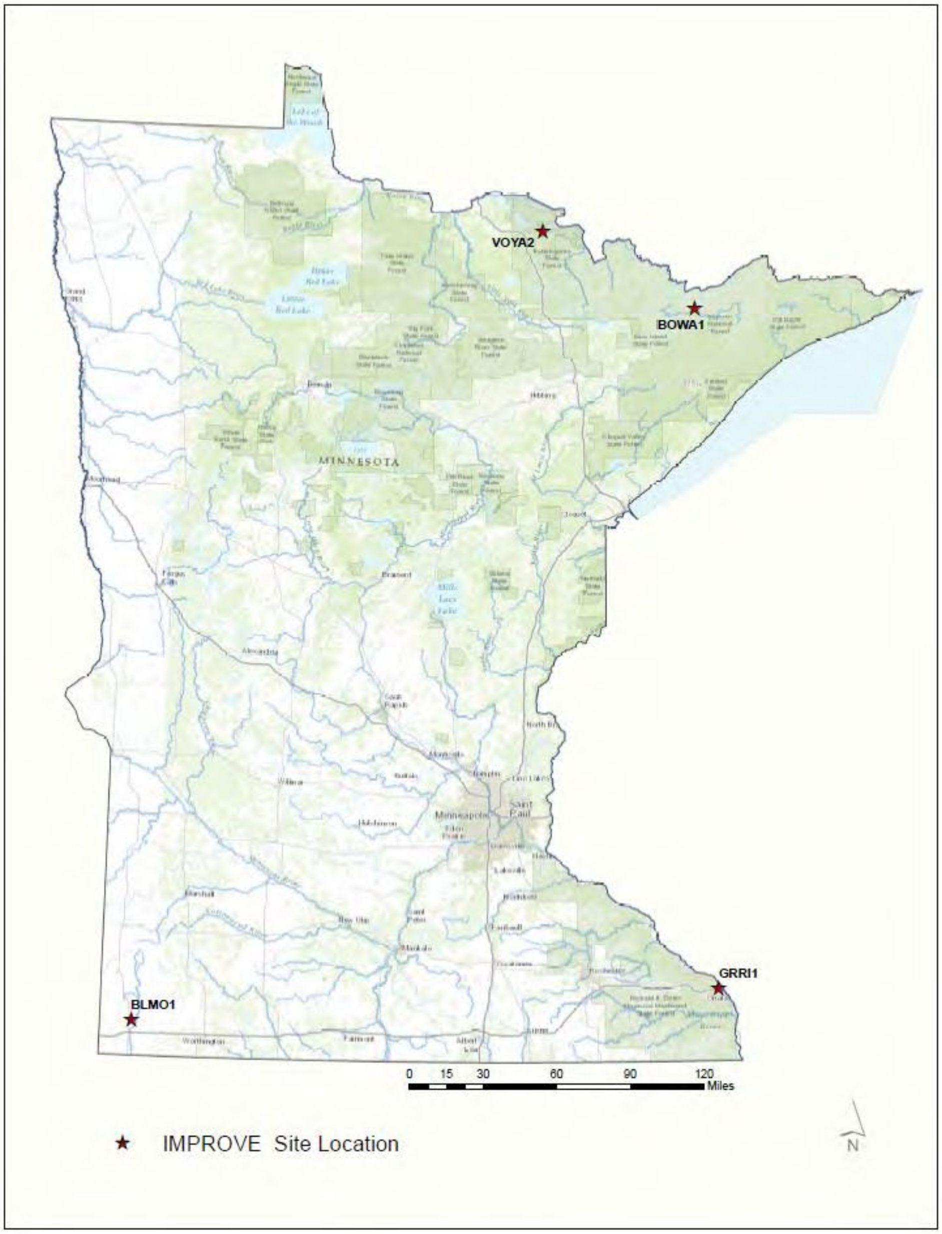
- To establish current visibility and aerosol conditions in Class I areas.
- To identify chemical species and emission sources responsible for existing man-made visibility impairment.
- To document long-term trends for assessing progress towards the national visibility goal.
- With the enactment of the Regional Haze Rule, to provide regional haze monitoring representing all visibility-protected federal Class I areas where practical.

The IMPROVE sites also provide $PM_{2.5}$ speciation data; therefore, they are a key component of the U.S. EPA’s national fine particle monitoring and are critical to tracking progress related to regional haze regulations.

In Minnesota, IMPROVE sites are located in the two Class I areas, at Boundary Waters (monitor BOWA1) and Voyageurs (monitor VOYA2). An IMPROVE Protocol site is located in southeastern corner of the state, near Great River Bluffs State Park (GRRI1). Another IMPROVE Protocol site, formerly located in the southwestern corner of the state, near Blue Mounds State Park (BLMO1) was discontinued by the IMPROVE network in December 2015. The locations of these monitors are shown in Figure 16 below.

[182] *See* Interagency Monitoring of Protected Visual Environments, *IMPROVE Program*, https://vista.cira.colostate.edu/Improve/improve-program/ (last visited July 6, 2022).

Figure 16. IMPROVE monitor sites in Minnesota



Minnesota commits to meeting the requirements under 40 CFR § 51.308(f)(6)(iv) to report to U.S. EPA visibility data for each of Minnesota's Class I areas annually. BOWA1 is managed by the U.S. Department of Agriculture, Forest Service. VOYA2 is managed by the U.S. Department of the Interior, National Park Service. GRR1 is managed by the Minnesota Department of Natural Resources. Filter samples from the IMPROVE modules are sent for analysis to the Crocker Nuclear Laboratory of the University of California in Davis and the analysis data is submitted to the Federal Land Manager Environmental Database (FED) and the U.S. EPA Air Quality System (AQS).[183] This fulfills Minnesota's requirement for electronic reporting of visibility data.

Additionally, U.S. EPA identifies in its August 2019 Guidance that the IMPROVE program's practice of providing data directly to U.S. EPA satisfies the requirements in 40 CFR § 51.308(f)(6)(iv) and (vi) of the Regional Haze Rule for the regional haze SIP to provide for reporting of visibility monitoring data to the Administrator at least annually.[184]

Continued operation of the IMPROVE network is contingent upon continued federal funding to measure, characterize, and report regional haze visibility impairment. In the event of a complete loss of federal funding, the MPCA will attempt to provide support for the operation of at least one of its two Class I IMPROVE sites.

Should the IMPROVE monitoring network be disbanded or reduced, Minnesota could use information from $PM_{2.5}$ monitoring sites in the state to make some estimates of $PM_{2.5}$ concentrations, and thus visibility impairment, in Class I areas. Minnesota evaluates its monitoring network periodically, including evaluation of technology changes and the need for new monitors. More information about the monitoring networks in place in Minnesota and any future planned changes, can be found in the Annual Air Monitoring Network Plan for Minnesota.[185]

2.8.5. Emissions inventory

The Regional Haze Rule requires states to provide for the preparation of a statewide emission inventory of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I area.[186] Regarding emission inventories, U.S. EPA notes in their August 2019 Guidance that this requirement is to provide for the preparation of emission inventories and that those emission inventories are not required SIP elements themselves.[187] U.S. EPA continues that a state may note that its compliance with the Air Emissions Reporting Requirements (40 CFR Part 51, Subpart A) satisfies the requirement to provide for an emissions inventory for the most recent year for which data are available.

As specified in the applicable U.S. EPA guidance, the pollutants inventoried by Minnesota include volatile organic compounds (VOC), nitrogen oxides (NO_X), fine particulate ($PM_{2.5}$), coarse particulate (PM_{10}), ammonia (NH_3), and sulfur dioxide (SO_2).

Minnesota rules require point sources to submit reports of their emissions to the MPCA each year and an annual point source emission inventory is produced.[188] Minnesota compiles a full statewide emission inventory every three years and submits this data to the National Emission Inventory (NEI). Minnesota will continue to update the full emission inventory on this three-year cycle.

Emissions developed for modeling platforms, including future projected emissions, is a multi-organization collaborative process described in Section 2.6.

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[183] *See* Federal Land Manager Environmental Database, https://views.cira.colostate.edu/fed/ (last visited June 23, 2022); U.S. EPA, Air Quality System (AQS), (May 18, 2022), ***https://www.epa.gov/aqs*** (last visited June 23, 2022).

[184] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 55.

[185] *See* MPCA, 2022 Air Monitoring Network Plan for Minnesota (June 2021), https://www.pca.state.mn.us/sites/default/files/aq10-20a.pdf.

[186] *See* 40 CFR 51.308(f)(6)(v).

[187] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 55.

[188] *See* Minn. R. 7019.3000.

2.9. Consultation

Regional haze is caused by a wide variety of pollution sources dispersed over a large geographic area. The Regional Haze Rule places specific emphasis on having states work collaboratively through regional planning and consultation processes. Throughout the development of this regional haze SIP revision, the MPCA met with states, FLMs, Tribes, regulated parties, non-governmental organizations (NGOs), and U.S. EPA to discuss technical information, early concepts, and early drafts of portions of this SIP revision.

2.9.1. Consultation with states

The Regional Haze Rule requires states consult with other states that have emissions that are reasonably anticipated to contribute to visibility impairment in the same Class I area(s), in order to develop coordinated emission management strategies for making reasonable progress. These requirements are specified in 40 CFR § 51.308(f)(2)(ii).

> *The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.*
>
> *(A) The State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.*
>
> *(B) The State must consider the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area.*
>
> *(C) In any situation in which a State cannot agree with another State on the emission reduction measures necessary to make reasonable progress in a mandatory Class I Federal area, the State must describe the actions taken to resolve the disagreement. In reviewing the State's implementation plan, the Administrator will take this information into account in determining whether the plan provides for reasonable progress at each mandatory Class I Federal area that is located in the State or that may be affected by emissions from the State. All substantive interstate consultations must be documented.*

U.S. EPA provides clarification in its August 2019 Guidance that the rule does not provide a definition of coordinated emission management strategies and suggests that the above requirement is procedural in nature and meant to ensure that states share and consider each other's technical information.[189]

The MPCA participated in monthly calls with U.S. EPA Region 5, states (Illinois, Indiana, Iowa, Michigan, Minnesota, Ohio, and Wisconsin), FLMs, and Tribes facilitated by LADCO known as the "LADCO Regional Haze Workgroup." These monthly calls began in January 2018, continued through until October 2021, and moved to a bimonthly schedule after the October 2021 call.

MPCA also met with representatives from specific states during the development of this SIP submittal. Information regarding the consultation between Minnesota and these states is provided below.

Iowa. MPCA contacted representatives from Iowa on June 1, 2022, for the purpose of state-to-state consultation as MPCA had identified Iowa emissions as reasonably anticipated to contribute to visibility impairment at Minnesota Class I areas. In a meeting on June 30, 2022, MPCA shared details regarding what Minnesota planned to include in its Regional Haze SIP submittal including the visibility contribution

[189] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 52.

analysis that MPCA performed to determine which Class I areas are potentially impacted by Minnesota sources and which states potentially impact Minnesota Class I areas. Minnesota identified that this was an opportunity for information sharing. MPCA requested that Iowa representatives provide any additional information regarding the approach their state is taking regarding emission reduction measures contemplated for the second regional haze implementation period.

On July 1, 2022, Iowa provided additional information identifying that they would be requiring their two largest EGUs, Louisa Generating Station and Walter Scott Jr. Energy Center, to make operational improvements to their existing control equipment. The improvements would result in an estimated 9,000 - 10,000 ton per year reduction in SO_2 emissions. The emission limits contemplated for these sources were still under development but were estimated to be equivalent to approximately 0.10 lb/MMBtu. These two EGUs were selected as part of Iowa's four-factor analysis process.

Michigan. MPCA contacted representatives from Michigan on June 1, 2022, for the purpose of state-to-state consultation as MPCA had identified Minnesota emissions as reasonably anticipated to contribute to visibility impairment at Michigan Class I areas. In a meeting on June 24, 2022, MPCA shared details regarding what Minnesota planned to include in its Regional Haze SIP submittal including the visibility contribution analysis that MPCA performed to determine which Class I areas are potentially impacted by Minnesota sources and which states potentially impact Minnesota Class I areas. Minnesota identified that this was an opportunity for information sharing. MPCA requested that Michigan representatives provide any additional information regarding the approach their state is taking regarding emission reduction measures contemplated for the second regional haze implementation period.

Michigan's identified approach was that no additional controls are needed for Michigan sources during the second regional haze implementation period. This was based on monitoring data that shows visibility remains below the level needed to demonstrate reasonable progress and several coal-fired EGUs in Michigan will be shutting down before and shortly after 2028.

Missouri. MPCA contacted representatives from Missouri on June 1, 2022, for the purpose of state-to-state consultation as MPCA had identified Missouri emissions as reasonably anticipated to contribute to visibility impairment at Minnesota Class I areas. In a meeting on June 21, 2022, MPCA shared details regarding what Minnesota planned to include in its Regional Haze SIP submittal including the visibility contribution analysis that MPCA performed to determine which Class I areas are potentially impacted by Minnesota sources and which states potentially impact Minnesota Class I areas. Minnesota identified that this was an opportunity for information sharing. MPCA requested that Missouri representatives provide any additional information regarding the approach their state is taking regarding emission reduction measures contemplated for the second regional haze implementation period.

On June 21, 2022, Missouri provided a link to their proposed Regional Haze SIP that was available for public notice in April 2022. Missouri's identified approach was that the on-the-books and on-the-way controls were sufficient to achieve reasonable progress goals alongside consent agreements with facilities selected as part of Missouri's four-factor analysis. In general, these consent agreements require the facilities to burn lower-sulfur coal and operate existing control devices at all times when burning coal in the affected emission units. Missouri identified that no additional measures beyond the newly established consent agreements were necessary to make reasonable progress in the second regional haze implementation period.

Nebraska. On June 26, 2020, representatives from Nebraska and MPCA met for the purpose of state-to-state consultation regarding Nebraska's process for source screening and selection for the four-factor analysis portion of their SIP planning process. Nebraska provided information on their source selection process and identified Nebraska sources that show impacts at Minnesota Class I areas. On December 16, 2020, Nebraska and MPCA met again to discuss the information they had received from Nebraska sources selected for a four-factor analysis, upcoming modeling information and source information expected for Nebraska, visibility glidepaths and RPGs, and the next steps in Nebraska's SIP development.

MPCA contacted representatives from Nebraska on June 1, 2022, for the purpose of state-to-state consultation as MPCA had identified Nebraska emissions as reasonably anticipated to contribute to visibility impairment at Minnesota Class I areas. In a meeting on June 21, 2022, MPCA shared details regarding what Minnesota planned to include in its Regional Haze SIP submittal including the visibility contribution analysis that MPCA performed to determine which Class I areas are potentially impacted by Minnesota sources and which states potentially impact Minnesota Class I areas. Minnesota identified that this was an opportunity for information sharing. MPCA requested that Nebraska representatives provide any additional information regarding the approach their state is taking regarding emission reduction measures contemplated for the second regional haze implementation period.

Nebraska previously identified that they were evaluating potential SO_2 emission controls for one Nebraska EGU and fuel switching (from coal to natural gas) for another Nebraska EGU. Nebraska's draft regional haze SIP was not available during the time period that this interstate consultation was conducted.

North Carolina. On June 25, 2020, representatives from North Carolina and MPCA met to discuss each state's process for source screening and selection for the four-factor analysis portion of their SIP planning process. Information discussed included the choice of emission inventory year, the Q/d methodology considered, and which sources were selected to conduct a four-factor analysis. Minnesota and North Carolina did not have additional discussions beyond this meeting as part of the state-to-state consultation process.

North Dakota. On March 22, 2021, representatives from North Dakota and MPCA met for the purpose of state-to-state consultation regarding North Dakota's process for source screening and selection for the four-factor analysis portion of their SIP planning process. On June 9, 2021, North Dakota notified Minnesota that they determined visibility in North Dakota Class I areas are not significantly impacted by Minnesota sources and Minnesota sources do not impede North Dakota's ability to make reasonable progress during the second regional haze implementation period. North Dakota also identified that they reviewed the impacts from North Dakota sources and do not believe they significantly impact visibility in Minnesota Class I areas

MPCA contacted representatives from North Dakota on June 1, 2022, for the purpose of state-to-state consultation as MPCA had identified North Dakota emissions as reasonably anticipated to contribute to visibility impairment at Minnesota Class I areas. In a meeting on June 23, 2022, MPCA shared details regarding what Minnesota planned to include in its Regional Haze SIP submittal including the visibility contribution analysis that MPCA performed to determine which Class I areas are potentially impacted by Minnesota sources and which states potentially impact Minnesota Class I areas. Minnesota identified that this was an opportunity for information sharing. MPCA requested that North Dakota representatives provide any additional information regarding the approach their state is taking regarding emission reduction measures contemplated for the second regional haze implementation period.

On July 14, 2022, North Dakota provided a summary that outlined North Dakota's approach for the second regional haze implementation period. North Dakota evaluated 10 facilities (six coal-fired EGUs and four non-EGUs) using the four-factor analysis process for potential additional emission reduction measures. From these sources, North Dakota modeled projected 2028 visibility conditions with additional emission reduction measures for two facilities (Antelope Valley Station and Coyote Station) using two scenarios determined from the four-factor analysis process. Ultimately, North Dakota determined that they would not require these additional control measures, based on the modeling analysis, for the second regional haze implementation period.

South Dakota. On September 15, 2021, representatives from South Dakota and MPCA met for the purpose of state-to-state consultation regarding South Dakota's process for source screening and selection for the four-factor analysis portion of their SIP planning process and the potential visibility impacts from South Dakota sources on Minnesota Class I areas. Minnesota and South Dakota did not have additional discussions beyond this meeting as part of the state-to-state consultation process.

Wisconsin. MPCA contacted representatives from Wisconsin on June 1, 2022, for the purpose of state-to-state consultation as MPCA had identified Wisconsin emissions as reasonably anticipated to contribute to visibility impairment at Minnesota Class I areas. In a meeting on June 30, 2022, MPCA shared details regarding what Minnesota planned to include in its Regional Haze SIP submittal including the visibility contribution analysis that MPCA performed to determine which Class I areas are potentially impacted by Minnesota sources and which states potentially impact Minnesota Class I areas. Minnesota identified that this was an opportunity for information sharing. MPCA requested that Wisconsin representatives provide any additional information regarding the approach their state is taking regarding emission reduction measures contemplated for the second regional haze implementation period.

On July 12, 2022, Wisconsin provided additional information regarding point source emission reductions at Wisconsin sources. This information focused on the additional emission reductions that were not included in the LADCO modeling analysis for 2028. This included additional reductions that were not contained in Wisconsin's July 2021 Regional Haze SIP. Wisconsin summarized the additional emission reductions in NO_X and SO_2 emissions from Wisconsin sources that were not included in the modeling analysis would total an approximate 9,400 tpy reduction in NO_X emissions and 6,400 tpy reduction in SO_2 emissions.

Interstate consultation summary. MPCA notified representatives from Iowa, Missouri, Nebraska, North Dakota, and Wisconsin that emissions from their states are reasonably anticipated to contribute to visibility impairment in Minnesota Class I areas. MPCA did not ask these states to undertake specific emissions reductions necessary to make reasonable progress for the second regional haze implementation period.

No states, within the LADCO region or otherwise, have notified Minnesota that they identified emissions from Minnesota sources as contributing to visibility impairment at their Class I areas. No states, within the LADCO region or otherwise, have asked Minnesota to undertake specific emissions reductions necessary to make reasonable progress for the second regional haze implementation period.

2.9.2. Consultation with FLMs

Coordination and consultation between states and FLMs is required by the Regional Haze Rule. Minnesota's Class I areas, Voyageurs and Boundary Waters, are managed by the National Parks Service and U.S. Forest Service, respectively. The specific requirements for state and FLM consultation are identified in 40 CFR § 51.308(i)(2).

> *The State must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the State's decisions on the long-term strategy. The opportunity for consultation will be deemed to have been early enough if the consultation has taken place at least 120 days prior*

to holding any public hearing or other public comment opportunity on an implementation plan (or plan revision) for regional haze required by this subpart. The opportunity for consultation on an implementation plan (or plan revision) or on a progress report must be provided no less than 60 days prior to said public hearing or public comment opportunity. This consultation must include the opportunity for the affected Federal Land Managers to discuss their:

(i) Assessment of impairment of visibility in any mandatory Class I Federal area; and
(ii) Recommendations on the development and implementation of strategies to address visibility impairment.

FLMs and Minnesota staff participated in the LADCO Regional Haze Workgroup calls and contributed to both technical and non-technical work used in the development of this SIP submittal. In addition, opportunities have been provided by LADCO for FLMs to review and comment on each of the technical documents developed by LADCO and included in this SIP submittal.

After the LADCO Regional Haze Workgroup calls moved from meeting every month to every two months, beginning after the October 2021 call, the MPCA scheduled additional meetings with the FLMs to discuss technical and non-technical work related specifically to Minnesota's Regional Haze SIP. These calls began in November 2021, continued every two months in-between the LADCO Regional Haze Workgroup calls, and are scheduled out to the end of Calendar Year 2022.

The MPCA provided a copy of Minnesota's draft Regional Haze SIP and supporting documents to the FLMs on May 11, 2022, to begin the official consultation period identified in 40 CFR § 51.308(i)(2). In this opportunity for consultation, the MPCA requested that the FLMs provide comments by July 11, 2022, and offered to facilitate additional meetings and discussions regarding areas of interest in the draft Regional Haze SIP if requested.

Subsequently, the MPCA met with representatives from the U.S. NPS and U.S. FS in a virtual meeting on June 30, 2022, to receive their recommendations and conclusions regarding the Regional Haze SIP for the second implementation period. Representatives from the U.S. FWS and staff from U.S. EPA Region 5 were invited as well.

The Regional Haze Rule also requires that a state include documentation of how it addresses comments provided by the FLMs regarding any SIP revision or progress report as specified in 40 CFR § 51.308(i)(3).

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.

The comment letters from the FLMs are included in Appendix G. Consultation Comments. A summary of the formal consultation between MPCA and the FLMs, including how the MPCA addressed the FLM comments, is available in Section 4.3.

The Regional Haze Rule also requires that a state must provide for continuing consultation between a state and FLMs as specified in 40 CFR § 51.308(i)(4).

The plan (or plan revision) must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required by this subpart, including development and review of implementation plan revisions and progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

Minnesota will continue to coordinate and consult with the FLMs during the development of future progress reports and plan revisions, as well as during the implementation of programs having the potential to contribute to visibility impairment in the Class I areas. The FLMs will continue to be consulted in the following instances:

- Development and review of implementation plan revisions.
- Review of the five-year progress reports.
- Development and implementation of other programs that may contribute to impairment of visibility in Class I areas.

Coordination and consultation will continue to occur, as needed, through LADCO regional haze workgroup calls and direct consultation between the MPCA and FLMs directly.

2.9.3. Discussion with Tribes

While not a requirement of the Regional Haze Rule, U.S. EPA encouraged states to maintain a dialogue with Tribes throughout the SIP development process.

Regular Regional Haze updates have been part of quarterly meetings with MPCA and Tribes since 2017. Prior to the start of the FLM consultation period described below, the MPCA previously presented on this Regional Haze Comprehensive Update at the January 13, 2022, Minnesota Tribal Environmental Council (MNTEC) meeting.

The MPCA also provided a copy of Minnesota's draft Regional Haze SIP and supporting documents to multiple Minnesota Tribe contacts at the start of the FLM consultation period on May 11, 2022. In this opportunity for early review, the MPCA requested that Tribes provide comments by July 11, 2022, and offered to facilitate additional meetings and discussions regarding areas of interest in the draft Regional Haze SIP if requested. Subsequently, the MPCA presented on this topic at the May 18, 2022 MNTEC meeting, and presentation materials and a copy of Minnesota's draft Regional Haze SIP were provided to the MNTEC attendees.

MPCA did not receive any comments letter from Minnesota Tribes prior to the close of consultation.

2.9.4. Discussion with U.S. EPA

While not a requirement of the Regional Haze Rule, U.S. EPA encouraged states to discuss their plans and progress in developing their regional haze SIP throughout the SIP development process with the associated U.S. EPA Regional Office.

U.S. EPA Region 5 and the MPCA hold bimonthly calls for SIP projects to discuss and share updates related to the different SIP work that the MPCA performs. This included regular updates regarding Regional Haze, as well as the other SIP projects, and opportunities to discuss the development of Minnesota's Regional Haze SIP with U.S. EPA Region 5 staff.

U.S. EPA and U.S. EPA Region 5 also participated in the LADCO Regional Haze Workgroup calls and contributed to both technical and non-technical work used in the development of this SIP. In addition, opportunities have been provided by LADCO for U.S. EPA to provide feedback on provisions of the Regional Haze Rule and associated guidance documents with respect to how they can be applied to a state's SIP.

On December 8, 2020, the MPCA provided U.S. EPA with a webpage link to where the four-factor analyses that the MPCA requested and the facility-provided responses were posted and a copy of the draft overview text included in Section 1 - Regional Haze program overview. U.S. EPA provided informal comments on the draft overview and source selection process on January 21, 2021, more detailed comments on the four-factor analyses on March 2, 2021, and additional information on issues raised by the FLMs regarding U.S. EPA's Control Cost Manual (i.e., interest rates, equipment lifespan, retrofit factors, operating restrictions in cost estimates, control efficiency as an enforceable requirement, and evaluating visibility metrics).

The MPCA also provided a copy of Minnesota's draft Regional Haze SIP and supporting documents to U.S. EPA at the start of the FLM consultation period on May 11, 2022. In this opportunity for early review, the MPCA requested that U.S. EPA provide comments by July 11, 2022, and offered to facilitate additional meetings and discussions regarding areas of interest in the draft Regional Haze SIP if requested.

Subsequently, the MPCA met with representatives from U.S. EPA in a virtual meeting on July 11, 2022, to receive their initial recommendations and conclusions regarding the Regional Haze SIP for the second implementation period. On July 22, 2022, U.S. EPA provided a written version of their informal comments on the draft Regional Haze SIP.

2.9.5. Discussion with other parties

While not a requirement of the Regional Haze Rule, MPCA also discussed portions of this regional haze SIP, during the development stages, with regulated parties and NGOs who requested information surrounding this regional haze SIP revision. Beginning with the RFI letters that were sent to facilities in January/February 2020, the MPCA discussed aspects of the Regional Haze Rule and the four-factor analyses requested throughout the SIP development process. MPCA attended quarterly state/mining meetings and met with the "Class of '85 Regulatory Response Group" an ad hoc utility group representing approximately 30 electricity generation companies. MPCA also met with interested environmental and advocacy groups including the Sierra Club and the National Parks Conservation Association.

The MPCA also posted draft materials and modeling outputs on the MPCA website throughout the SIP development process.

2.10. Five-year progress report

Minnesota's progress report for the first implementation period was previously submitted on December 30, 2014. In U.S. EPA's August 2019 Guidance, they recommend that the progress report elements included in the SIP revision for the second implementation period cover a time period approximately from the first full year that was not in the previous progress report through a year that is as close as possible to the submission date of the SIP revision.[190]

For Minnesota, this means that the relevant time period to address for each of the elements of 40 CFR § 51.308(g)(1)-(5) is roughly 2015 through 2021. The specific elements of 40 CFR § 51.308(g)(1)-(5) are discussed in more detail below.

2.10.1. Status of control strategies

40 CFR § 51.308(g)(1) requires a description of the status of emission reduction measures:

> *A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State.*

In the first implementation period, the focus of the Regional Haze Rule was on establishing BART for certain older sources and reasonable progress towards national visibility goals. A full discussion of these

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[190] *See* U.S. EPA, Aug. 2019 EPA Guidance, *supra*, at 55.

strategies is available in Minnesota's 2014 5-year update.[191] However, in the second implementation period there are no BART requirements; therefore, the focus is on making reasonable progress.

As previously discussed in Section 2.5.7, Minnesota included the Northeast Minnesota Plan as part of long-term strategy in the first regional haze implementation period. This plan established emission reduction targets for 2012 and 2018, and those emission reduction targets have been met.

In addition, Minnesota taconite facilities subject to a Regional Haze FIP have not fully implemented control technology pending settlement agreements. The history and status of FIP implementation is described in Section 1.3.

2.10.2. Emissions reductions from regional haze SIP strategies

40 CFR § 51.308(g)(2) requires a summary of the emissions reductions from regional haze SIP strategies:

> *A summary of the emissions reductions achieved throughout the State through implementation of the measures described in [40 CFR § 51.308(g)(1)].*

Minnesota achieved most reductions for this implementation period before the 2014 progress update, but emissions from EGUs have continued to decrease under the CSAPR rule. Total EGU SO_2 emissions in 2021 were 6068 tons (down from 24,366 in 2013). Total EGU NOx emissions in 2021 were 11,392 tons (down from 24,855 tons in 2013).[192]

2.10.3. Visibility progress

40 CFR § 51.308(g)(3) requires an assessment of visibility conditions and changes for each Class I area within the state:

> *For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report.*
>
> *(i)(A) …the current visibility conditions for the most impaired and least impaired days.*
> *(ii)(A) …the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions.*
> *(iii)(A) …the change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under [40 CFR § 51.308(f)].*

Minnesota asked U.S. EPA about the visibility metric used to address the progress report elements due to the other requirements for comprehensive SIP updates focusing on clearest days, but the rule referenced above seems to indicate that states should focus on the least impaired days. Jackie Ashley (U.S. EPA, Office of Air Quality Planning and Standards), provided the following response on March 25, 2020:

> *Thank you for raising this question from MN. Effectively, "least impaired days" as used in the 1999 rule (and here in the 2017 rule) is the same as the newer term, "20% clearest days". The use of the term "least impaired days" remains in the 2017 rule to maintain consistency with the rule text for 1st*

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[191] *See* MPCA, Five-Year Regional Haze Progress Report State Implementation Plan (Dec. 30, 2014), https://www.pca.state.mn.us/sites/default/files/aq-sip2-17.pdf.
[192] *See U.S. EPA, Power Sector Emissions Data,* CLEAN AIR MARKETS PROGRAM DATA, https://campd.epa.gov.

planning period requirements. But both "least impaired days" and "clearest days" should be determined based on the 20% of days with the lowest deciview index values, regardless of the source of impairment (anthropogenic or natural). Therefore, in the context of the 2017 rule language, least impaired days and clearest days are the same.

Therefore, please note that while the above rule language uses the term "least impaired days", the remainder of this section will use the term "clearest days".

Minnesota's most impaired days have continued to improve since the 2014 progress update.[193] In 2019, the Boundary Waters Canoe Area 5-year average light extinction was 13.4 dv, down from 15.4 dv in 2014. Voyageurs National Park improved from 16.2 dv to 13.5 dv over the same time period. Clearest days have also improved during this implementation period. Boundary Waters' clearest days have reduced average light extinction from 4.9 dv in 2014 to 4.2 dv in 2019. Voyageurs National Park improved from 5.8 dv to 5.1 dv over the same time period.

2.10.4. Emissions progress

40 CFR § 51.308(g)(4) requires an analysis of emissions changes since the last regional haze SIP revision:

An analysis tracking the change over the period since the period addressed in the most recent plan required under [40 CFR § 51.308(f)] in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of [40 CFR Part 51, Subpart A] as of a date 6 months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date 6 months preceding the required date of the progress report. The State is not required to backcast previously reported emissions to be consistent with more recent emissions estimation procedures, and may draw attention to actual or possible inconsistencies created by changes in estimation procedures.

Minnesota statewide emissions trends were sourced from the State Tier 1 CAPS data tool.[194] The following figures and tables display activity-specific emissions trends from 2014 (the most recent Minnesota Regional Haze Progress Report) through 2021. Fuel combustion at electrical utilities and vehicle emissions have achieved the most emission reductions, but other activities have generally reduced or maintained emissions. Wildfire and prescribed fire emissions vary substantially year to year. Industrial fuel combustion increased slightly over this time period.

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[193] *See* MPCA Data Services, VISIBILITY PROGRESS AT MINNESOTA CLASS I AREAS (May 6, 2021), https://public.tableau.com/app/profile/mpca.data.services/viz/RegionalHaze_visibility_metrics_public/Visibilityprogress (last visited June 24, 2022).

[194] *See* U.S. EPA, AIR POLLUTANT EMISSIONS TRENDS DATA, https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data *(accessed* 05/03/2021).

Figure 17. Minnesota fuel combustion emissions from EGUs (2014 - 2021)

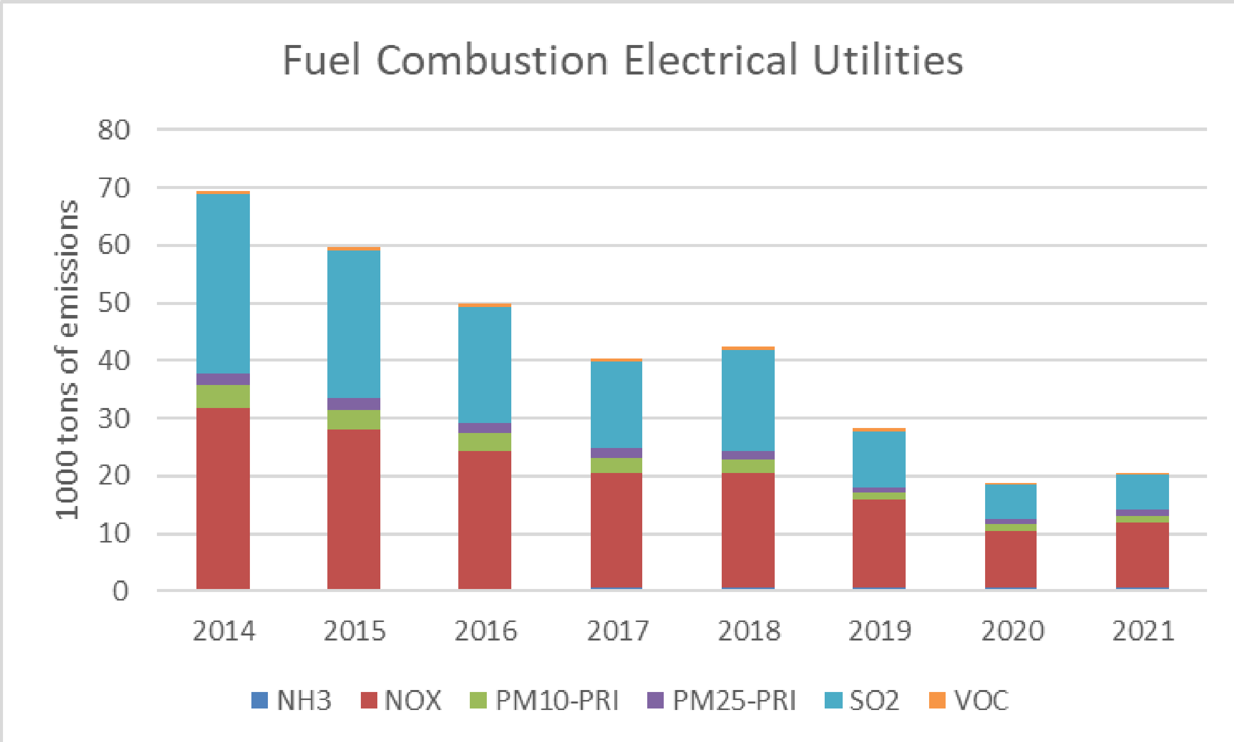

Table 67. Minnesota fuel combustion emissions from EGUs (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	0.45	0.48	0.51	0.54	0.57	0.59	0.59	0.59
NO_X	31.35	27.58	23.81	20.03	20.02	15.25	9.85	11.34
PM_{10}	3.91	3.44	2.97	2.50	2.12	1.25	1.25	1.25
$PM_{2.5}$	2.11	2.03	1.94	1.85	1.44	0.89	0.89	0.89
SO_2	30.93	25.55	20.17	14.79	17.61	9.82	5.80	6.07
VOC	0.69	0.65	0.61	0.57	0.57	0.39	0.39	0.39

Fuel combustion at electrical utilities has decreased significantly through the first implementation period through coal unit retirements and improved pollution control technology.

Figure 18. Minnesota fuel combustion emissions from industrial sources (2014 - 2021)

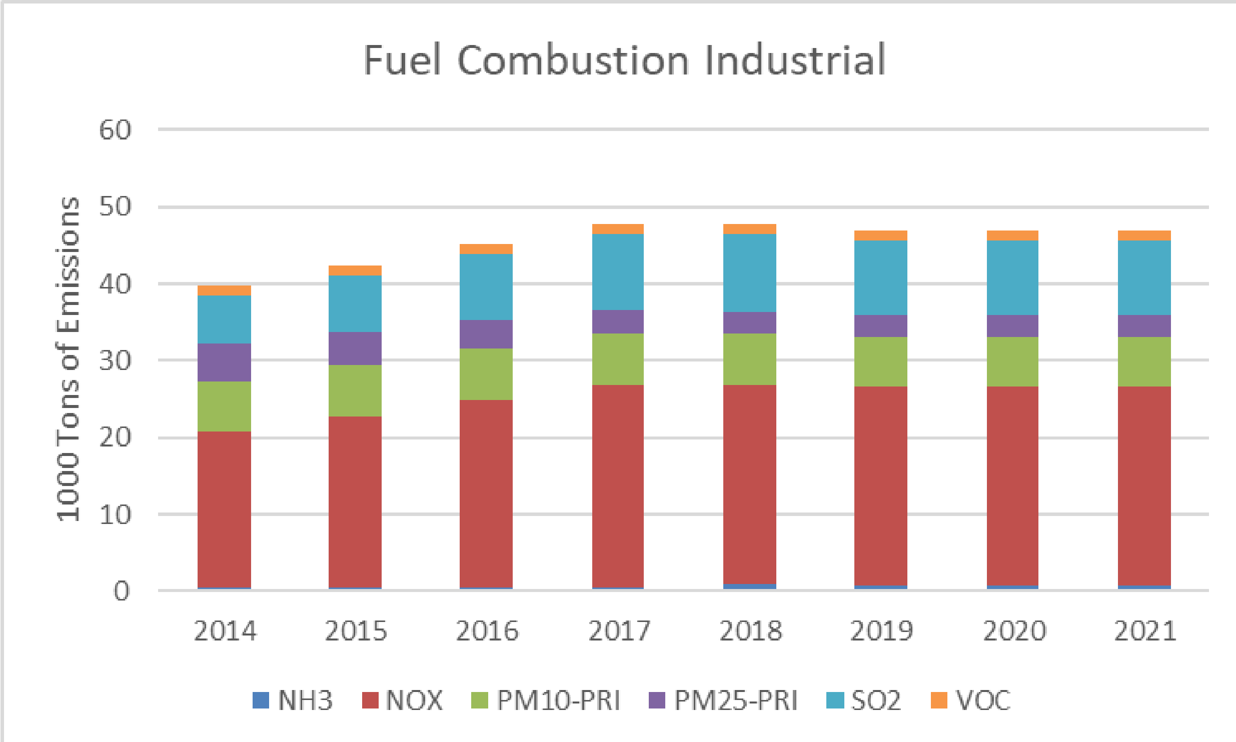

Table 68. Minnesota fuel combustion emissions from industrial sources (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	2015	2016	2017	2018	2019	2020	2021
NH_3	0.51	0.51	0.51	0.50	0.84	0.74	0.74	0.74
NO_X	20.18	22.29	24.39	26.42	26.06	25.88	25.88	25.88
PM_{10}	6.51	6.57	6.62	6.65	6.58	6.54	6.54	6.54
$PM_{2.5}$	5.04	4.34	3.63	2.90	2.84	2.81	2.81	2.81
SO_2	6.24	7.48	8.71	9.94	10.07	9.68	9.68	9.68
VOC	1.23	1.27	1.32	1.31	1.34	1.21	1.21	1.21

Fuel combustion at industrial facilities has increased slightly through the first implementation period. Industrial emissions fluctuate with changes in the economy.

Figure 19. Minnesota fuel combustion emissions from other sources (2014 - 2021)

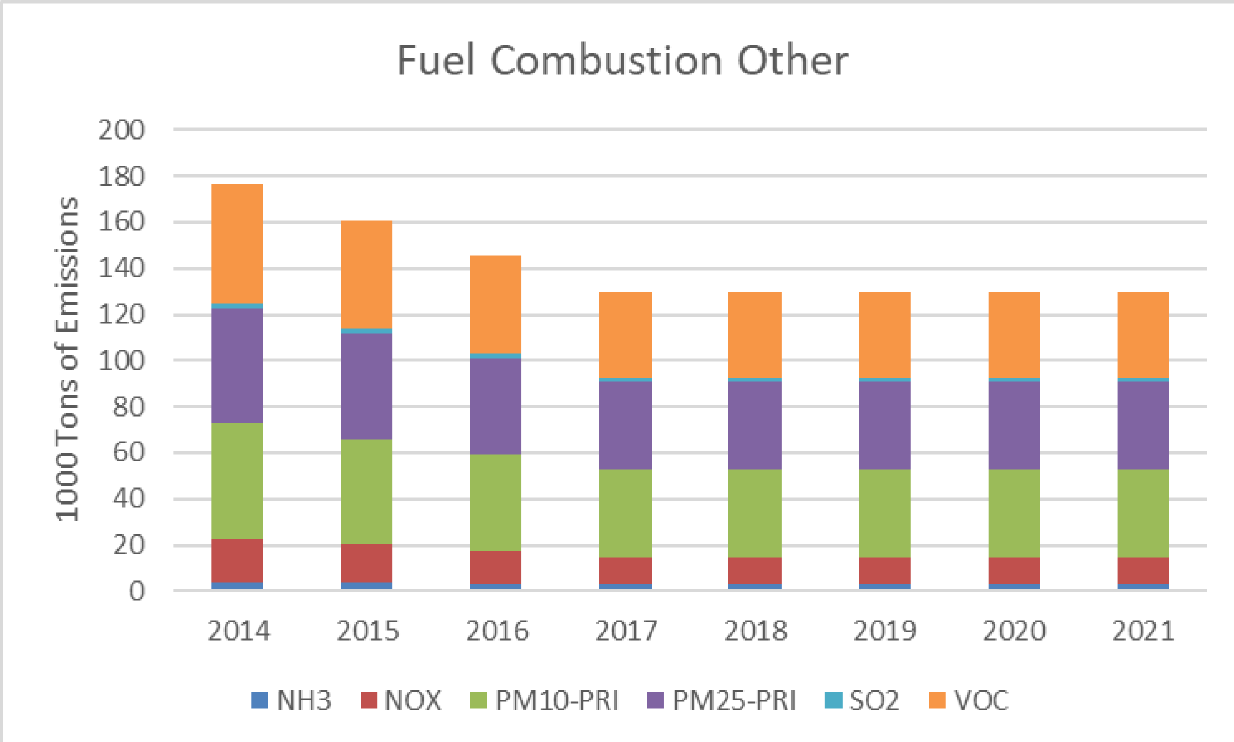

Table 69. Minnesota fuel combustion emissions from other sources (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	3.85	3.57	3.28	3.00	3.00	3.00	3.00	3.00
NO_X	18.86	16.49	14.12	11.76	11.76	11.81	11.81	11.81
PM_{10}	49.83	45.90	41.97	38.05	38.05	38.05	38.05	38.05
$PM_{2.5}$	49.74	45.83	41.91	38.00	38.00	38.01	38.01	38.01
SO_2	2.39	2.07	1.75	1.43	1.43	1.43	1.43	1.43
VOC	51.49	46.90	42.32	37.74	37.73	37.74	37.74	37.74

Other fuel combustion has decreased through the first implementation period.

Figure 20. Minnesota emissions from chemical and allied product manufacturing (2014 - 2021)

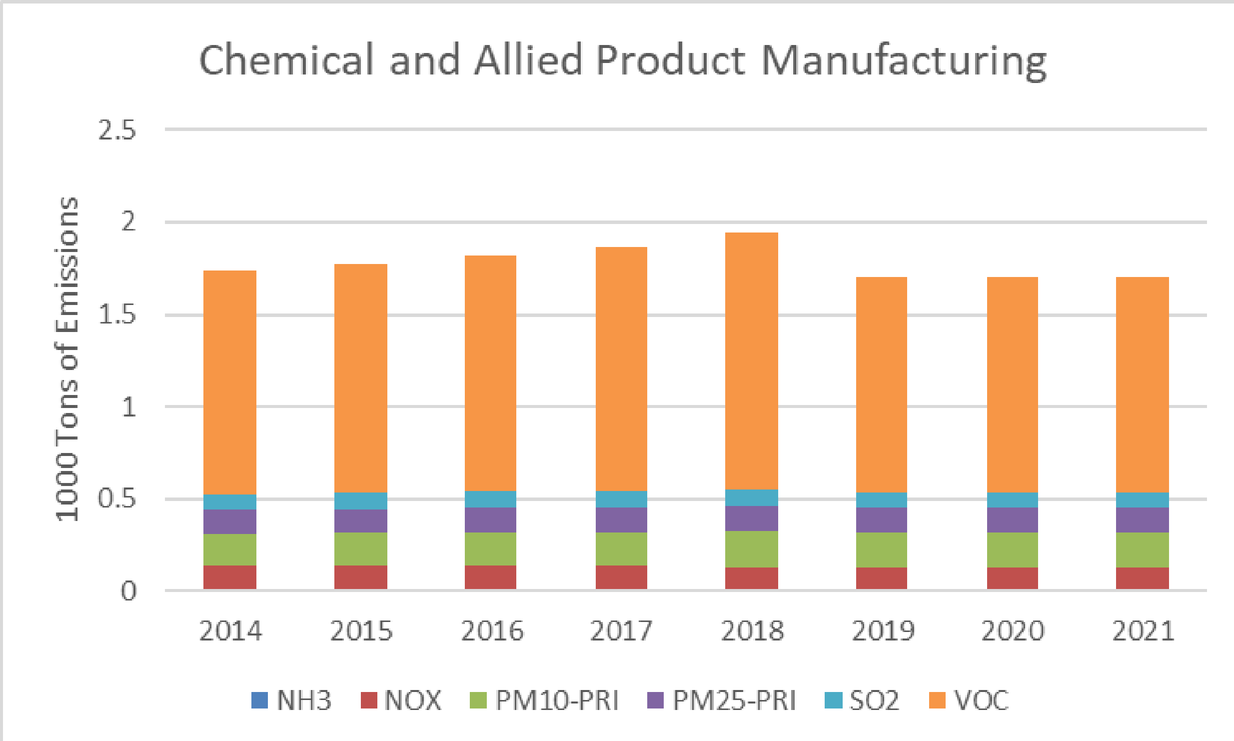

Table 70. Minnesota emissions from chemical and allied product manufacturing (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
NO_X	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
PM_{10}	0.18	0.18	0.18	0.18	0.19	0.18	0.18	0.18
$PM_{2.5}$	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14
SO_2	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
VOC	1.21	1.24	1.28	1.32	1.40	1.16	1.16	1.16

Emissions from chemical and allied product manufacturing remained stable through the first implementation period.

Figure 21. Minnesota emissions from metal processing (2014 - 2021)

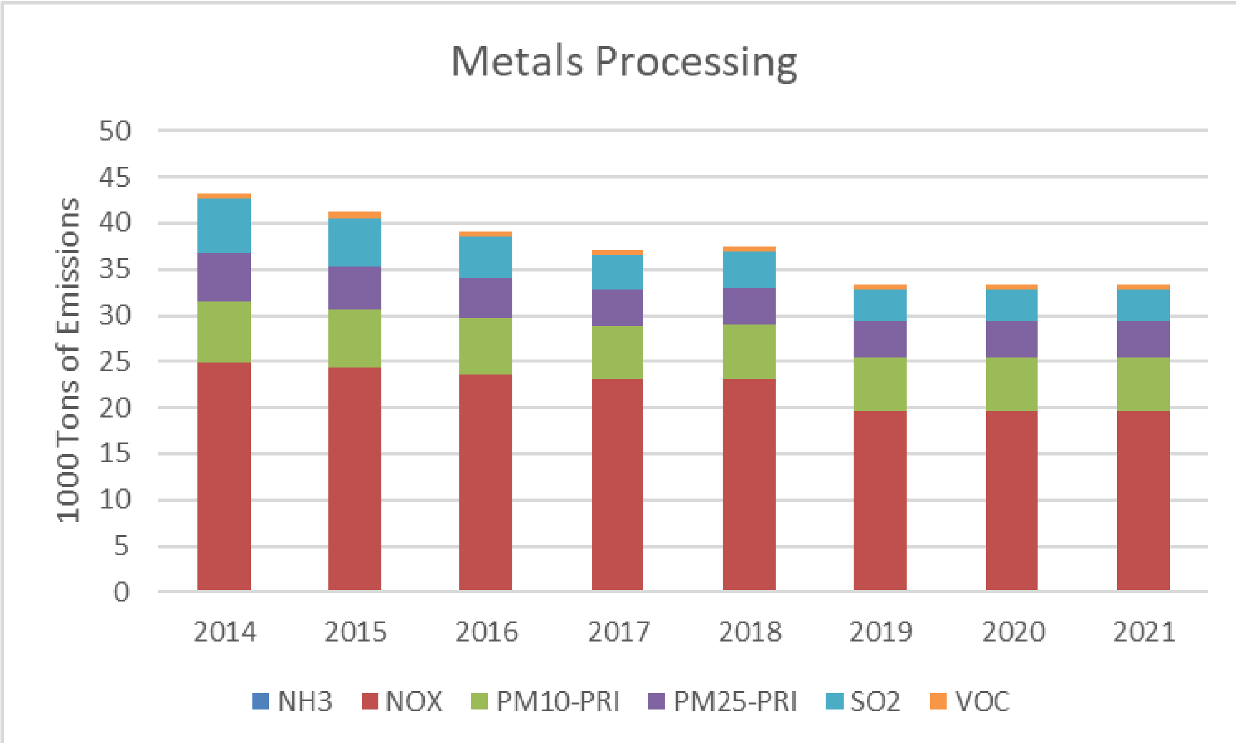

Table 71. Minnesota emissions from metal processing (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	2015	2016	2017	2018	2019	2020	2021
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO_X	24.86	24.25	23.63	23.02	23.13	19.75	19.75	19.75
PM_{10}	6.75	6.41	6.08	5.74	5.88	5.69	5.69	5.69
$PM_{2.5}$	5.08	4.71	4.34	3.97	3.94	3.90	3.90	3.90
SO_2	5.92	5.20	4.48	3.76	3.92	3.52	3.52	3.52
VOC	0.62	0.59	0.56	0.53	0.54	0.48	0.48	0.48

Emissions from metals processing decreased through the first implementation period.

Figure 22. Minnesota emissions from petroleum and related industries (2014 - 2021)

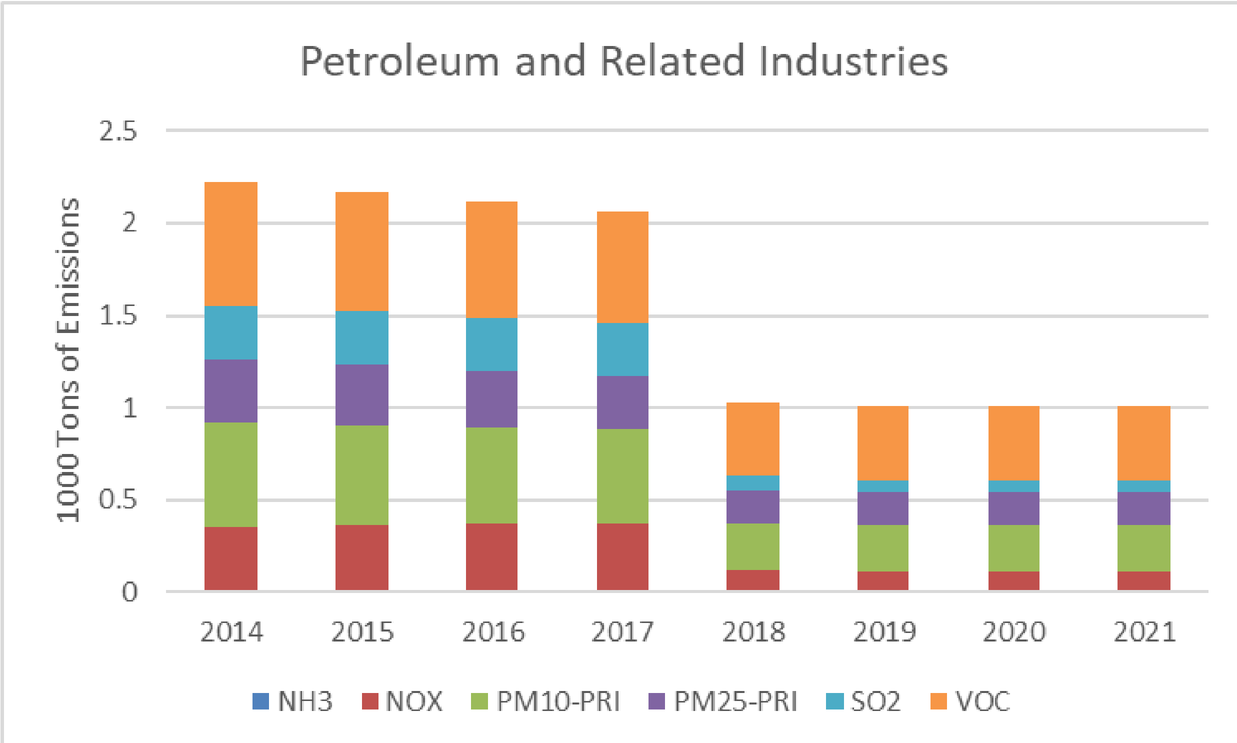

Table 72. Minnesota emissions from petroleum and related industries (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	2015	2016	2017	2018	2019	2020	2021
NH_3	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
NO_X	0.35	0.36	0.36	0.36	0.11	0.10	0.10	0.10
PM_{10}	0.56	0.54	0.52	0.50	0.25	0.25	0.25	0.25
$PM_{2.5}$	0.34	0.33	0.31	0.29	0.18	0.17	0.17	0.17
SO_2	0.29	0.29	0.29	0.29	0.08	0.06	0.06	0.06
VOC	0.67	0.65	0.63	0.60	0.39	0.40	0.40	0.40

Emissions from petroleum and related industries decreased through the first implementation period.

Figure 23. Minnesota emissions from other industrial processes (2014 - 2021)

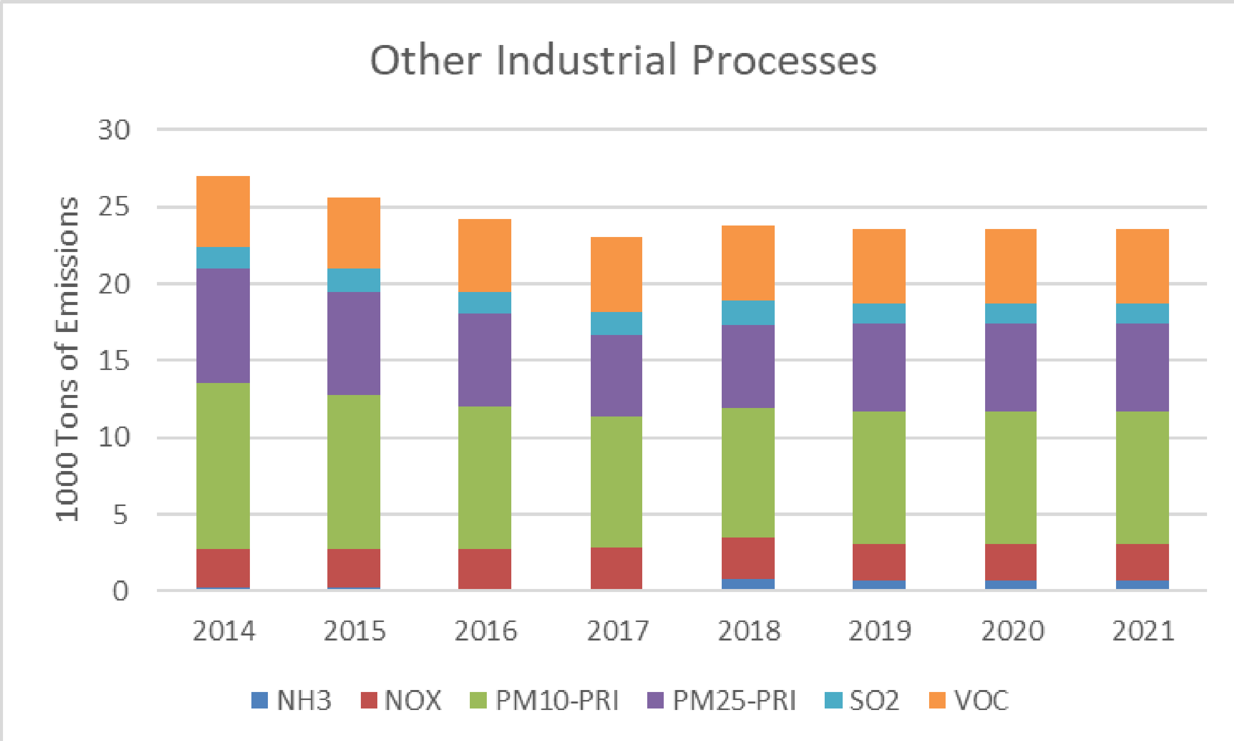

Table 73. Minnesota emissions from other industrial processes (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	0.23	0.21	0.19	0.17	0.81	0.68	0.68	0.68
NO_X	2.50	2.54	2.58	2.69	2.67	2.35	2.35	2.35
PM_{10}	10.85	10.05	9.26	8.48	8.38	8.69	8.69	8.69
$PM_{2.5}$	7.40	6.70	6.01	5.34	5.43	5.66	5.66	5.66
SO_2	1.41	1.43	1.44	1.46	1.63	1.31	1.31	1.31
VOC	4.60	4.66	4.73	4.84	4.83	4.92	4.92	4.92

Emissions from other industrial processes remained stable through the first implementation period.

Figure 24. Minnesota emissions from solvent utilization (2014 - 2021)

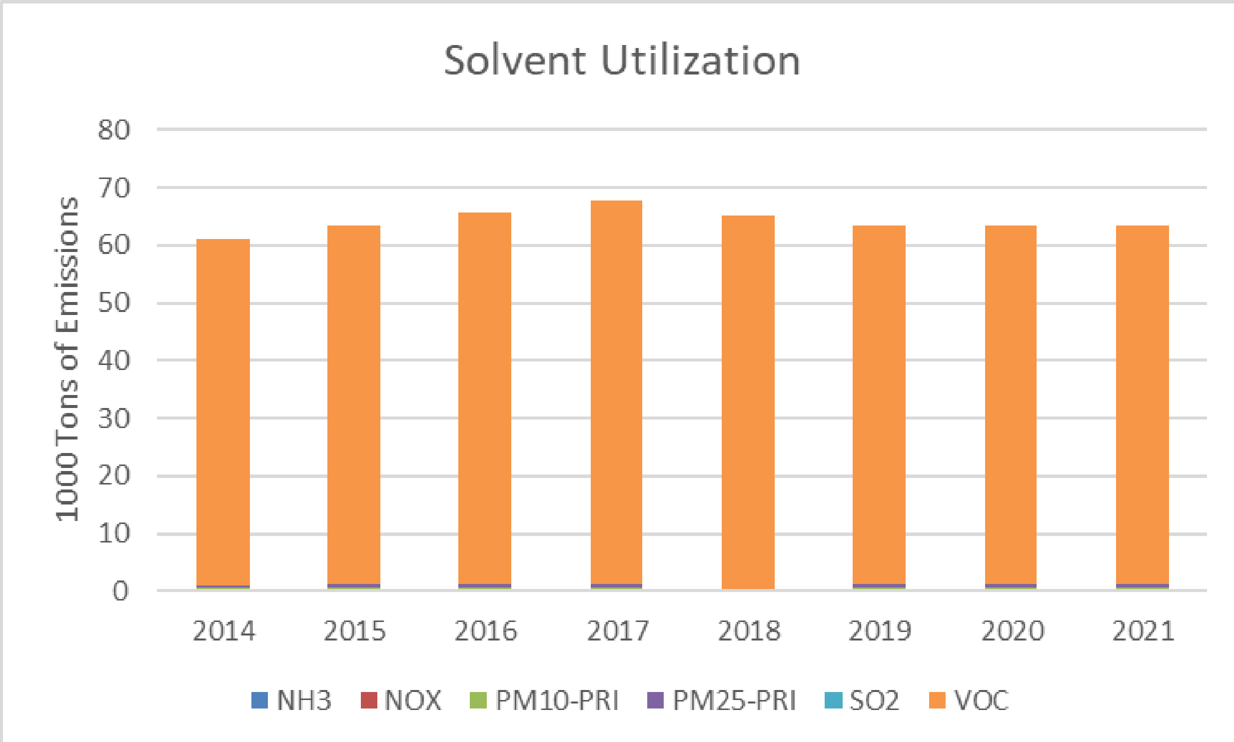

Table 74. Minnesota emissions from solvent utilization (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	0.01	0.01	0.00	0.00	-	0.00	0.00	0.00
NO_X	0.01	0.01	0.01	0.01	-	0.01	0.01	0.01
PM_{10}	0.59	0.62	0.65	0.68	-	0.67	0.67	0.67
$PM_{2.5}$	0.50	0.52	0.55	0.57	-	0.57	0.57	0.57
SO_2	0.00	0.00	0.00	0.00	-	0.01	0.01	0.01
VOC	60.00	62.18	64.36	66.54	64.98	62.15	62.15	62.15

Emissions from solvent utilization remained stable through the first implementation period.

Figure 25. Minnesota emissions from storage and transport (2014 - 2021)

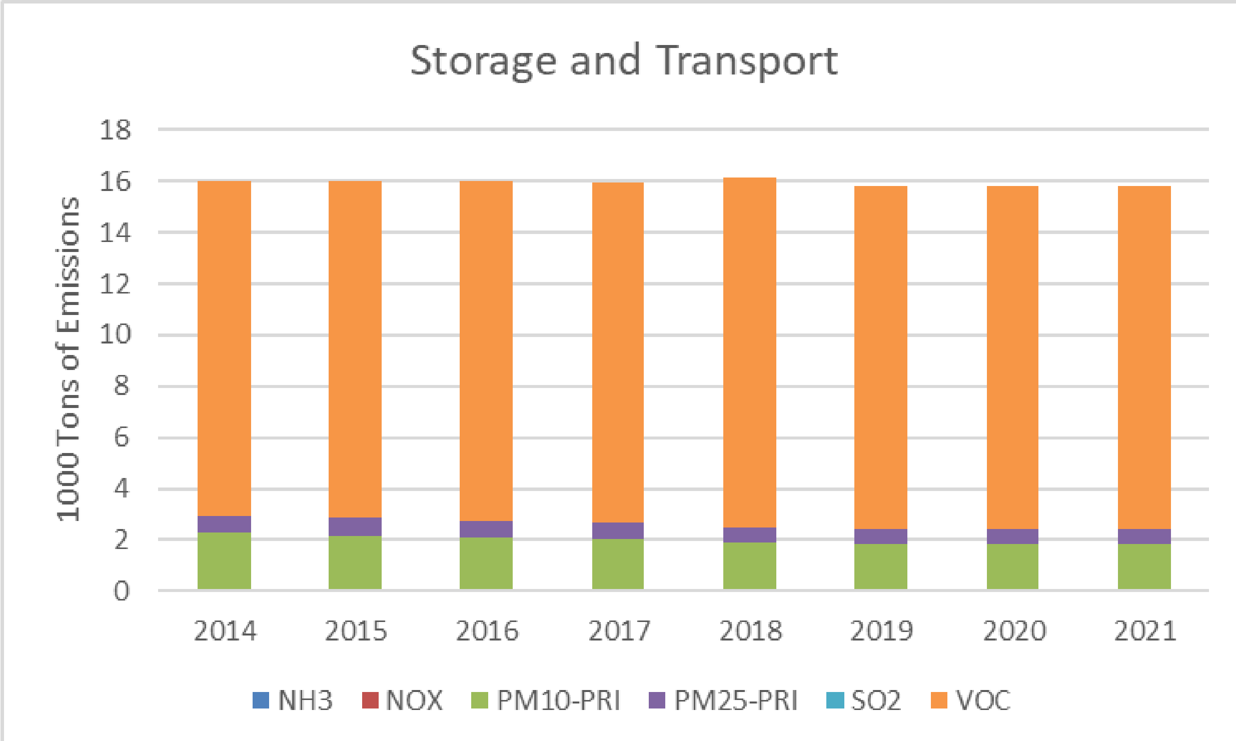

Table 75. Minnesota emissions from storage and transport (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO_X	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05
PM_{10}	2.20	2.13	2.05	1.97	1.84	1.78	1.78	1.78
$PM_{2.5}$	0.67	0.66	0.64	0.63	0.61	0.57	0.57	0.57
SO_2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VOC	13.08	13.16	13.24	13.33	13.64	13.43	13.43	13.43

Emissions from storage and transport remained stable through the first implementation period.

Figure 26. Minnesota emissions from waste disposal and recycling (2014 - 2021)

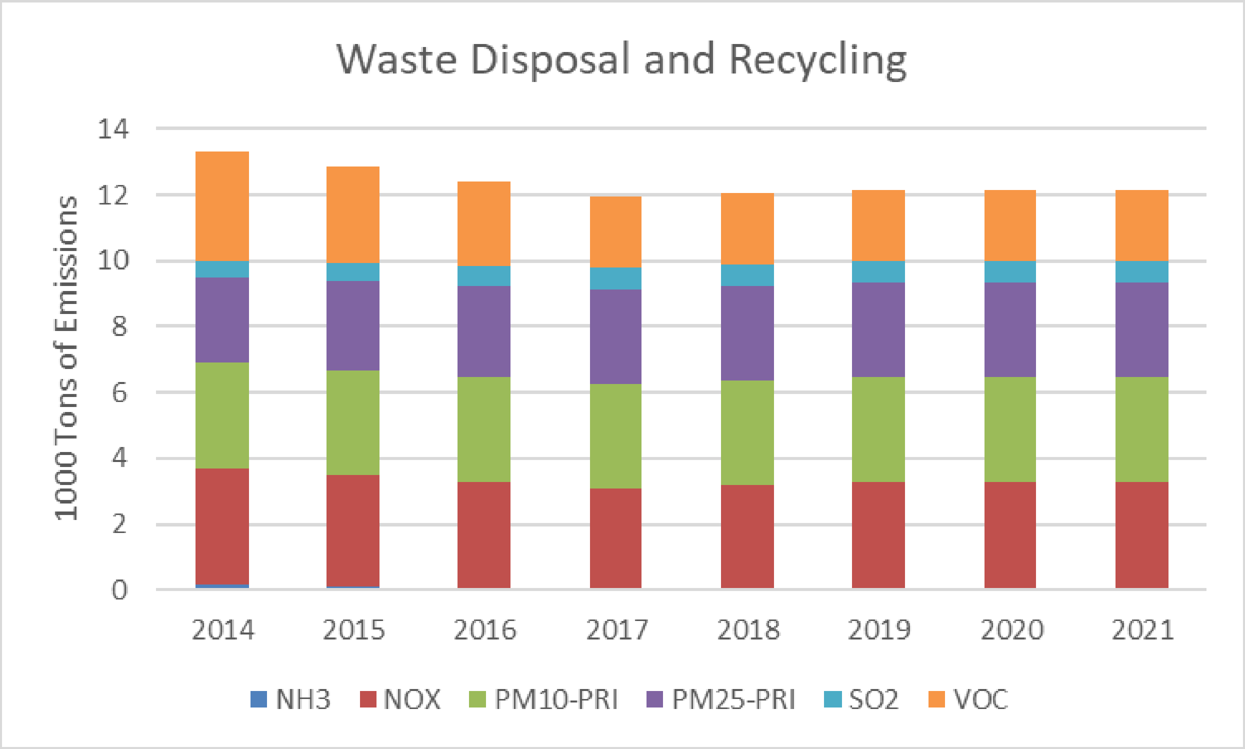

Table 76. Minnesota emissions from waste disposal and recycling (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	2015	2016	2017	2018	2019	2020	2021
NH_3	0.16	0.11	0.06	0.01	0.01	0.01	0.01	0.01
NO_X	3.56	3.40	3.24	3.07	3.19	3.26	3.26	3.26
PM_{10}	3.18	3.18	3.17	3.17	3.16	3.17	3.17	3.17
$PM_{2.5}$	2.61	2.70	2.79	2.87	2.87	2.87	2.87	2.87
SO_2	0.50	0.55	0.60	0.65	0.65	0.68	0.68	0.68
VOC	3.32	2.94	2.56	2.18	2.18	2.18	2.18	2.18

Emissions from waste disposal and recycling remained stable through the first implementation period.

Figure 27. Minnesota emissions from highway vehicles (2014 - 2021)

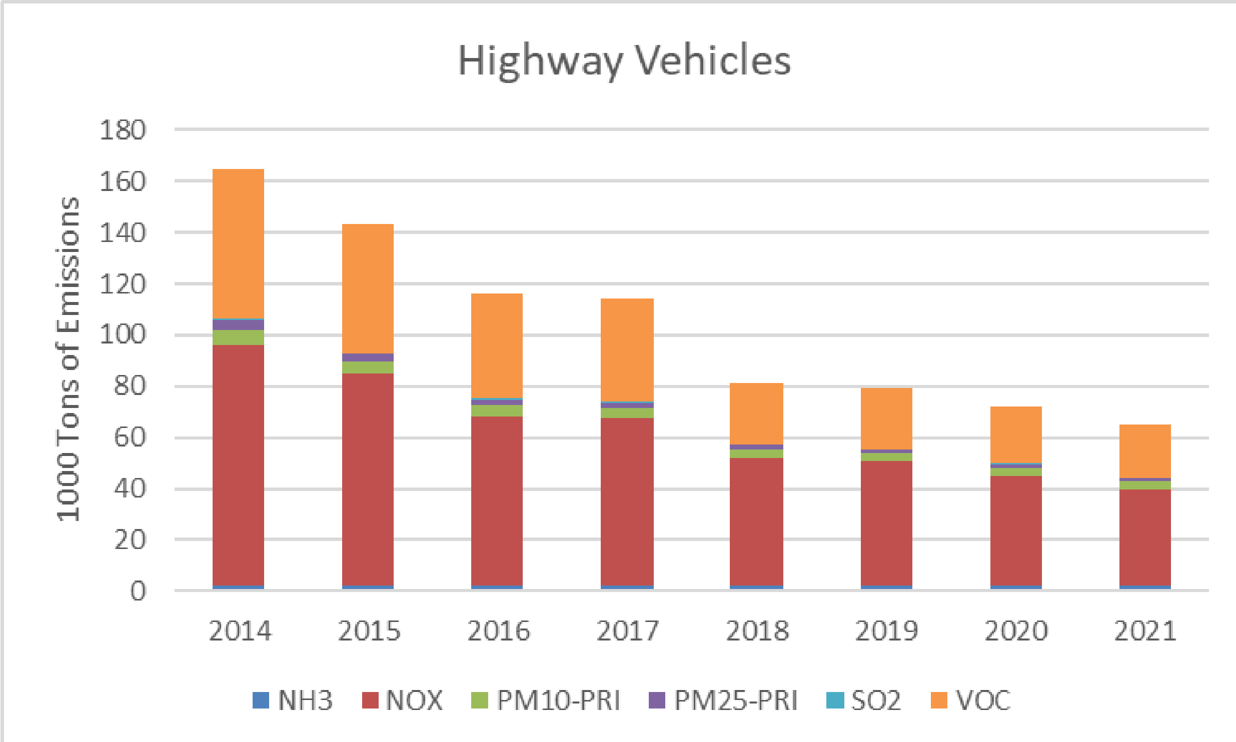

Table 77. Minnesota emissions from highway vehicles (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	2.14	2.00	1.92	1.95	1.95	1.94	1.92	1.91
NO_X	94.17	82.85	66.47	65.64	50.23	48.48	43.07	37.65
PM_{10}	5.76	4.92	4.03	3.98	3.22	3.32	3.22	3.12
$PM_{2.5}$	3.57	2.82	2.19	2.13	1.48	1.56	1.42	1.29
SO_2	0.46	0.39	0.39	0.36	0.31	0.25	0.23	0.22
VOC	58.39	50.51	41.38	39.88	23.98	23.79	22.20	20.61

Emissions from highway vehicles declined significantly through the first implementation period due to more stringent vehicle emission standards and fleet turnover.

Figure 28. Minnesota emissions from off-highway vehicles (2014 - 2021)

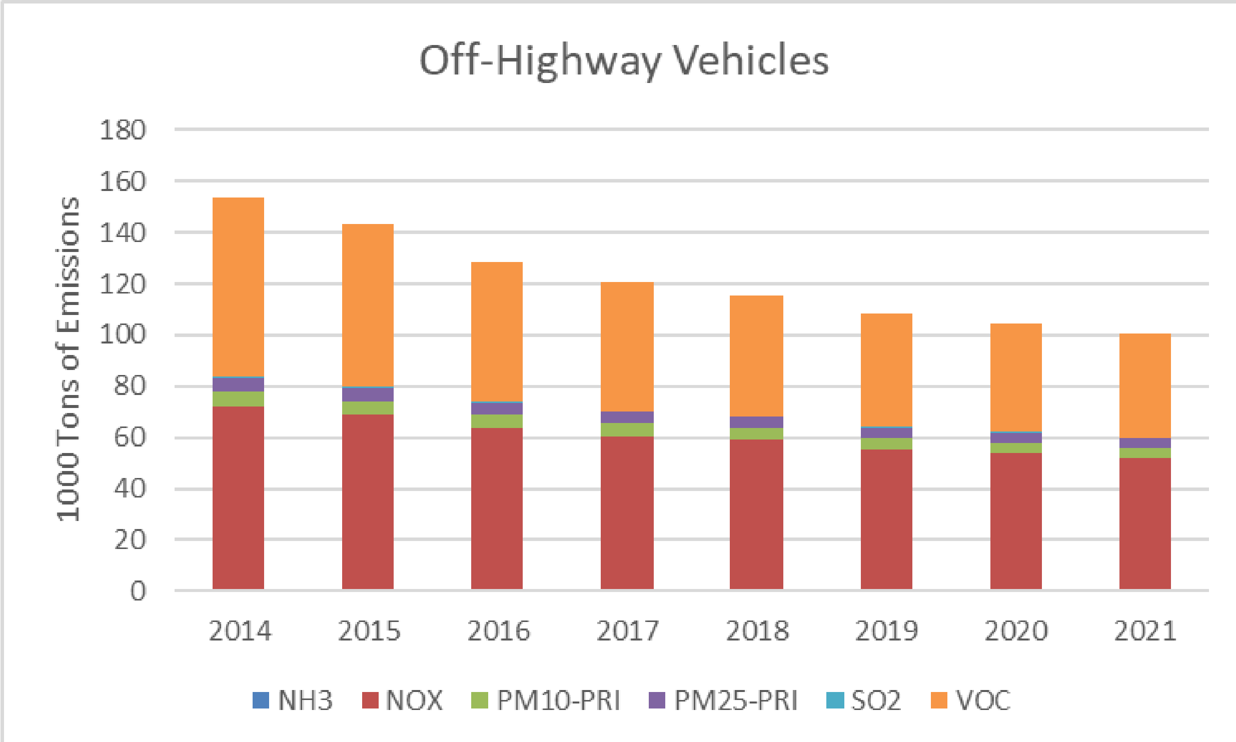

Table 78. Minnesota emissions from off-highway vehicles (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	2015	2016	2017	2018	2019	2020	2021
NH_3	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09
NO_X	71.85	68.56	63.41	60.48	58.93	55.41	53.55	51.70
PM_{10}	5.74	5.45	5.11	4.84	4.58	4.35	4.15	3.95
$PM_{2.5}$	5.43	5.16	4.86	4.60	4.35	4.14	3.94	3.74
SO_2	0.45	0.49	0.59	0.37	0.34	0.33	0.33	0.33
VOC	69.93	63.44	54.03	50.01	47.07	44.19	42.62	41.05

Emissions from off-highway vehicles declined through the first implementation period due to Diesel Emissions Reductions Act projects and other vehicle replacements.

Figure 29. Minnesota emissions from miscellaneous sources (2014 - 2021)

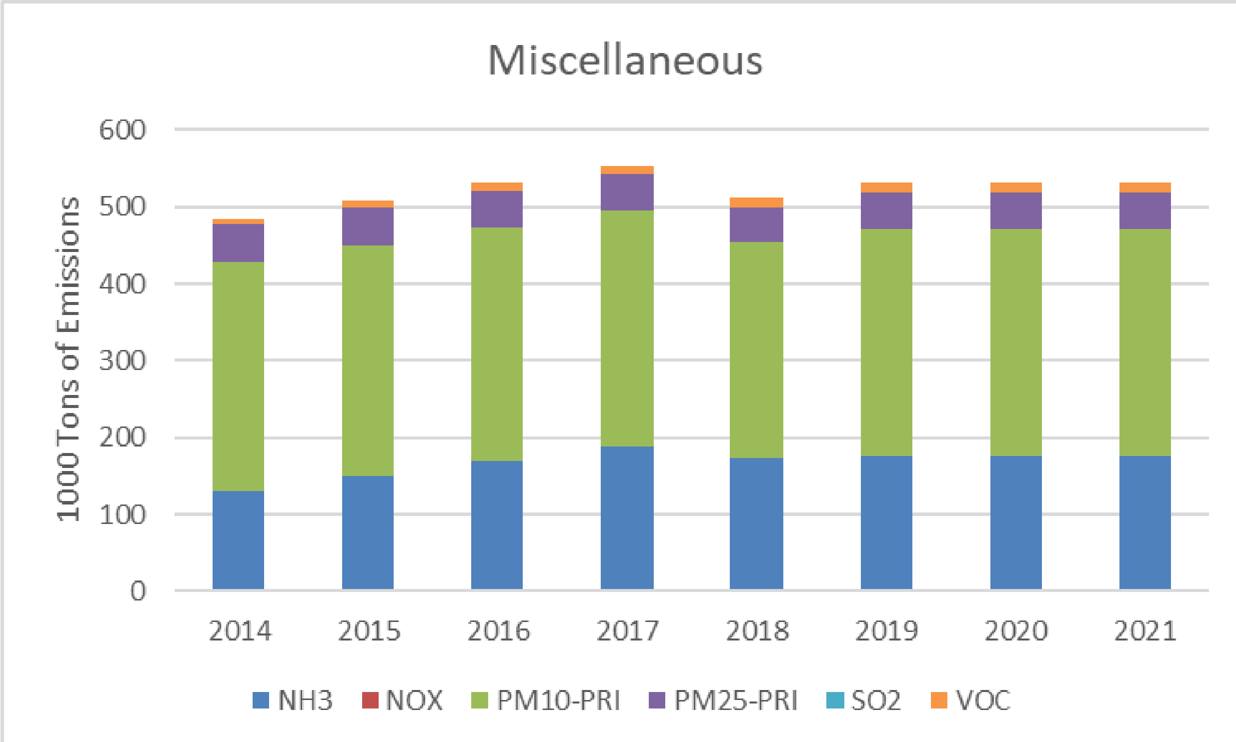

Table 79. Minnesota emissions from miscellaneous sources (2014 - 2021)

Pollutant	**Annual emissions data (in 1000s of tons)**							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	129.96	149.21	168.45	187.69	173.14	176.02	176.02	176.02
NO_X	0.10	0.09	0.08	0.07	0.27	0.49	0.49	0.49
PM_{10}	297.18	300.98	304.77	307.23	281.02	294.74	294.74	294.74
$PM_{2.5}$	49.62	48.95	48.28	47.27	44.99	47.53	47.53	47.53
SO_2	0.02	0.02	0.01	0.01	0.07	0.09	0.09	0.09
VOC	8.17	9.07	9.96	10.86	12.07	12.87	12.87	12.87

Emissions from miscellaneous sources remained stable through the first implementation period.

Figure 30. Minnesota emissions from wildfires (2014 - 2021)

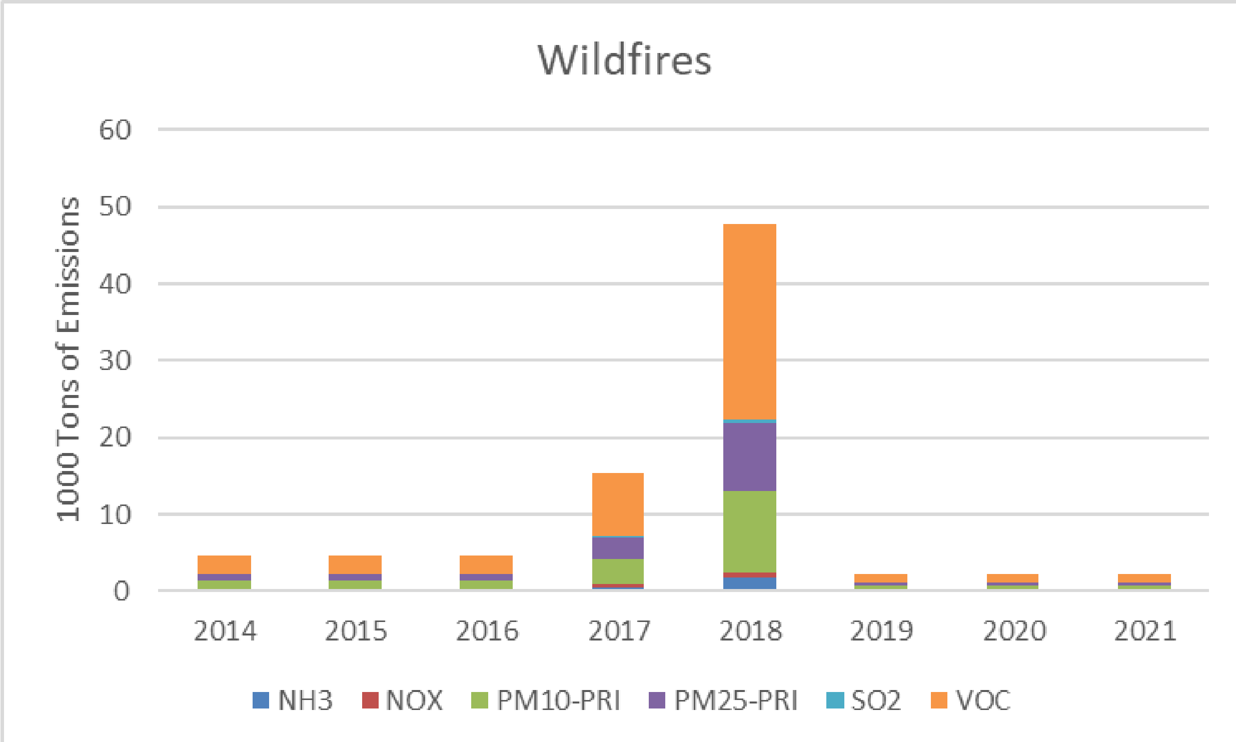

Table 80. Minnesota emissions from wildfires (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
NH_3	0.16	0.16	0.16	0.56	1.77	0.08	0.08	0.08
NO_X	0.15	0.15	0.15	0.29	0.77	0.07	0.07	0.07
PM_{10}	1.00	1.00	1.00	3.34	10.41	0.50	0.50	0.50
$PM_{2.5}$	0.85	0.85	0.85	2.83	8.83	0.42	0.42	0.42
SO_2	0.08	0.08	0.08	0.20	0.60	0.04	0.04	0.04
VOC	2.29	2.29	2.29	8.06	25.44	1.15	1.15	1.15

Emissions from wildfires varied significantly through the first implementation period. Wildfires vary in severity and frequency year to year, although climate change has increased their severity and frequency.

Figure 31. Minnesota emissions from prescribed fires (2014 - 2021)

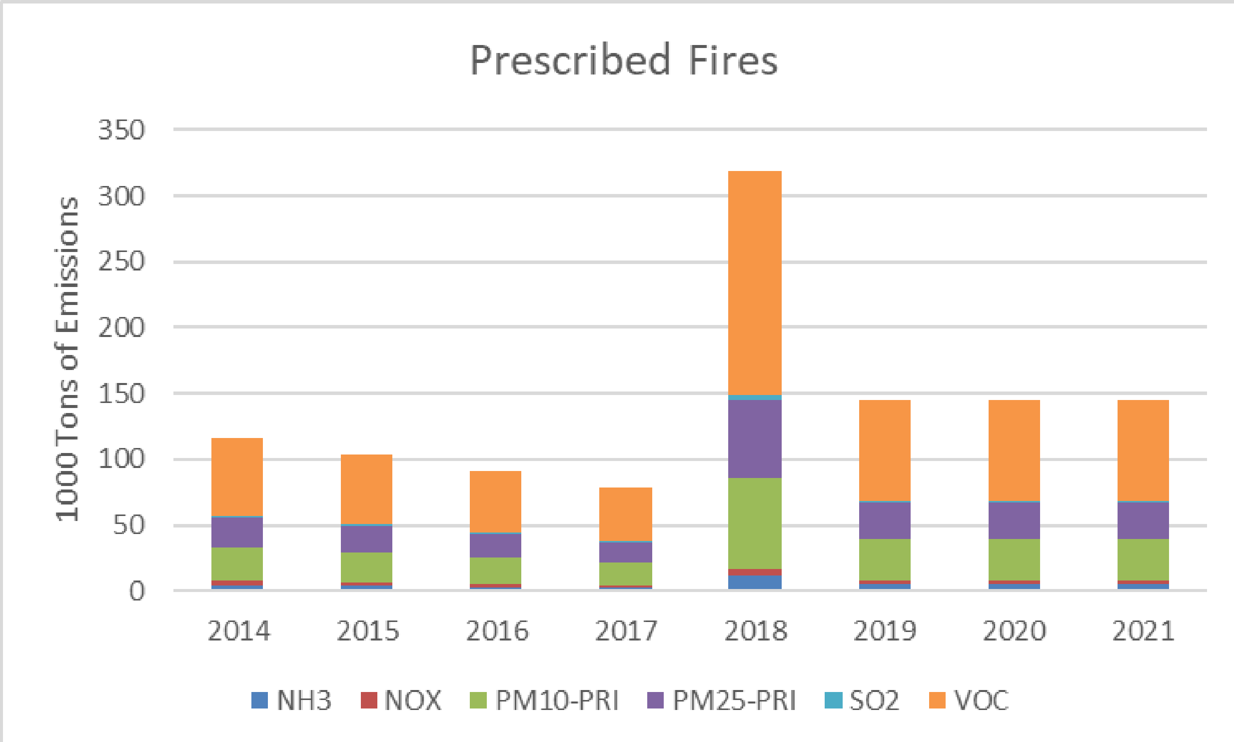

Table 81. Minnesota emissions from prescribed fires (2014 - 2021)

Pollutant	Annual emissions data (in 1000s of tons)							
	2014	2015	2016	2017	2018	2019	2020	2021
NH_3	4.09	3.67	3.25	2.83	11.84	5.35	5.35	5.35
NO_X	3.86	3.23	2.59	1.95	4.83	2.64	2.64	2.64
PM_{10}	25.70	22.88	20.06	17.24	69.46	31.72	31.72	31.72
$PM_{2.5}$	21.78	19.39	17.00	14.61	58.86	26.88	26.88	26.88
SO_2	2.01	1.73	1.45	1.17	3.91	1.90	1.90	1.90
VOC	58.76	52.74	46.73	40.72	170.22	76.84	76.84	76.84

Emissions from prescribed fires varied through the first implementation period. Prescribed fire emissions may change as land management patterns change in Minnesota.

2.10.5. Assessment of changes impeding visibility progress

40 CFR § 51.308(g)(5) requires an assessment of changes impeding visibility progress:

> *An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under [40 CFR § 51.308(f)] including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.*

Minnesota has continued to make significant progress in reducing anthropogenic emissions within the state. Many of these reductions, particularly from EGUs, were anticipated in the first implementation period. One significant increase has been VOC contributions from North Dakota, primarily from the Oil and Gas sector. This increase has not significantly impeded progress as Minnesota remains below the glidepath but may need evaluation in future implementation periods.

3. Supplemental information on Minnesota's Regional Haze actions

3.1. Non-point pollution reductions

Minnesota has addressed non-point sources of regional haze precursors though rulemaking, Volkswagen Settlement funds, and U.S. EPA Advance projects for Ozone and PM. The MPCA also provides small business assistance and other pollution prevention support statewide. The brief summaries below include non-point emission reductions that may benefit Regional Haze but are not a complete inventory of state work on these emission sources. Minnesota will continue to pursue emission reductions from non-point sources to reach our 2064 Regional Haze goals.

3.1.1. Ozone and PM Advance Programs:

Highlights from the 2019-2021 work on Ozone Advance and PM Advance projects include:

- Grants awarded to four small businesses to reduce VOC emissions from solvents and coatings and 2 more projects for Ethylene Oxide reduction
- Grants awarded to 103 businesses and organizations to upgrade their landscaping equipment to electric models, 60% of these in Fiscal Year (FY)2020, and 83% of these in FY2021 were in areas of concern for environmental justice
- 18 companies using safer chemicals
- Project Green Fleet replaced or upgraded 29 heavy-duty diesel engines with cleaner alternatives
- 195 high-emitting vehicles in low-income communities in the Twin Cities Metro area had emission control equipment repaired
- Business Pollution Prevention grant program started by the Ramsey & Washington Recycling and Energy Board to decommission PERC dry cleaners and reduce VOCs

In the time from July 2019 to June 2021, CAM Partners reduced over 636 tons of emissions of volatile organic compounds (VOCs), Particulate Matter less than 2.5 micrometers (PM2.5), and nitrogen oxides (NOx).[195]

3.1.2. Volkswagen Settlement Funds

Minnesota was awarded $47 Million in the Volkswagen Settlement and has distributed approximately $14 Million to replace dirty diesel vehicles and invest in electric vehicle technology. Through those grants, MPCA estimates emission reductions of:

- 1,900 tons of NO_X reduced
- 191.9 tons of $PM_{2.5}$ reduced[196]

These reductions reflect significant improvements in off-road diesel equipment, heavy-duty on-road vehicles, and school bus replacements.

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[195] See MPCA, 2020-2021 Minnesota Ozone and Particulate Matter Advance Programs Update (March 8, 2022).
[196] MCPA, *Progress toward our goals*, VOLKSWAGEN SETTLEMENT, https://www.pca.state.mn.us/air/progress-toward-our-goals (last visited June 27, 2022).

3.1.3. Clean Cars MN Rulemaking

Minnesota adopted Low Emission Vehicle and Zero Emission Vehicle standards in 2021. Over the first ten years of implementation (2024-2034), the rules are estimated to reduce light duty vehicle NMOG+NO_X emissions by 6,095 tons and PM emissions by 3,245 tons.[197]

4. Procedural Requirements

4.1. Clean Air Act § 110(l) noninterference requirements

Under CAA § 110(l), U.S. EPA cannot approve a SIP revision if it would interfere with attainment of the NAAQS, reasonable further progress toward attainment, or any other applicable requirement of the CAA.[198] Therefore, a SIP revision requesting revisions to SIP approved rules may only be approved if the state has demonstrated that the revision will not interfere with attainment or maintenance with any NAAQS. In evaluating whether a given SIP revision would interfere with attainment or maintenance, as required by section 110(l), U.S. EPA generally considers whether the SIP revision will preserve or improve the status quo in air quality.

The revisions to Minnesota's Regional Haze SIP proposed in this action do not impact Minnesota's ability to attain and maintain the NAAQS and do not reduce the MPCA's authorities or any enforceable standards. Specifically, the revisions to Minnesota's Regional Haze SIP serve three primary purposes:

- Address the requirements of the Regional Haze Rule for the second implementation period, which extends through 2028.
- Revise Minnesota's long-term strategy to include the compilation of enforceable emissions, limitations, compliance schedules, and other measures necessary to make reasonable progress.
- Develop and establish reasonable progress goals (RPGs) for 2028 at the Boundary Waters and Voyageurs Class I areas for the second implementation period that provide for reasonable progress towards achieving natural visibility conditions.

Regional Haze Rule requirements. Addressing the requirements of the Regional Haze Rule are not expected to have any negative environmental consequences, and may have a positive environmental benefit, as they are intended to improve visibility conditions through emission reduction efforts.

Revisions to Minnesota's long-term strategy. The revisions to Minnesota's long-term strategy includes establishing enforceable requirements for permitted sources that have planned emission unit retirements, implementation of existing effective control technologies, implementation of federal programs in Minnesota and surrounding states, and new emission reduction targets for permitted sources in Northeastern Minnesota. These measures are expected to have a positive environmental benefit as they are intended to improve visibility conditions through emission reduction efforts.

Establishing 2028 RPGs at Minnesota Class I areas. The new RPGs established for the Boundary Waters and Voyageurs Class I areas for 2028 are below the URP glidepath and show marked improvement on the 20% most impaired days and show no degradation on the 20% clearest days in 2028 compared to 2000-2004 conditions. This demonstrates that the emission reduction measures known at the time of the regional scale modeling to set the RPGs provided for a positive environmental benefit. Furthermore, the new RPGs do not reflect all emission reduction measures included in the long-term strategy as

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[197] Statement of Need and Reasonableness, Adopting Vehicle Greenhouse Gas Emissions Standards (Clean Cars Minnesota) 79 (Dec. 2020), https://www.pca.state.mn.us/sites/default/files/aq-rule4-10m.pdf.
[198] *See CAA § 110, 42 U.S.C. § 7410(l).*

discussed in Section 2.6.2, so additional improvement in visibility conditions would be expected from the additional emission reductions that were not included in the regional scale modeling.

Summary. The revisions to Minnesota's Regional Haze SIP are not a relaxation of existing requirements and have no impact on Minnesota's ability to attain and maintain the NAAQS. In accordance with CAA § 110(l), the analysis above demonstrates that the revisions to Minnesota's Regional Haze SIP for the second implementation period will not interfere with the attainment or maintenance of the NAAQS.

4.2. Public notice and comment period

This section will be completed upon conclusion of the public notice period.

Public notice period: August 22, 2022 - October 7, 2022

Public information meeting: September 22, 2022 (MPCA St. Paul office and virtual meeting)

The public notice for the comprehensive update to Minnesota's Regional Haze SIP was published in the State Register on August 22, 2022, the public comment period commenced on August 22, 2022, and ended on October 7, 2022. During the public notice period, a copy of the SIP revision was made available at the MPCA office located in St. Paul and on the MPCA's website. A copy of the public notice is included in Appendix H. Public Notice, Comment Letters, and MPCA Response-to-Comments.

The public notice stated:

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

MPCA received [#] comment letters prior to the close of the public comment period and [#] late comment letters regarding this comprehensive SIP revision. The comment letters and MPCA's responses are included in Appendix H. Public Notice, Comment Letters, and MPCA Response-to-Comments.

4.3. Consultation with Federal Land Managers

This section describes the formal consultation held between the MPCA and the FLMs. A summary of informal consultation between MPCA and the FLMs is available in Section 2.9.2.

FLM consultation period: May 11, 2022 - July 11, 2022

FLM consultation meeting: June 30, 2022 (virtual meeting)

The MPCA began formal consultation with the Federal Land Managers by providing an early draft of this SIP document to representatives from the National Park Service (U.S. NPS), U.S. Fish & Wildlife Service

(U.S. FWS), and U.S. Forest Service (U.S. FS). The SIP document and supporting materials were provided to the FLMs on May 11, 2022. The MPCA requested that the FLMs provide comments by July 11, 2022, and offered to facilitate additional meetings and discussions regarding areas of interest in the draft Regional Haze SIP if requested.

Subsequently, the MPCA met with representatives from the U.S. NPS and U.S. FS in a virtual meeting on June 30, 2022, to receive their recommendations and conclusions regarding the Regional Haze SIP for the second implementation period. Representatives from the U.S. FWS and staff from U.S. EPA Region 5 were invited as well.

MPCA received two comment letters prior to the close of consultation. The U.S. NPS provided their letter via email on July 11, 2022. The U.S. FS notified provided their letter via email on July 12, 2022. MPCA did not receive a comment letter from the U.S. FWS prior to the close of consultation. The comment letters from the FLMs are included in Appendix G. Consultation Comments.

MPCA made changes to the following sections of the Regional Haze SIP submittal based on this consultation with FLMs.

Table 82. FLM consultation comments and MPCA response

Section	FLM Comment	MPCA Response
	U.S. Forest Service Comments	
N/A	Introduction General positive comments on the SIP overall regarding content, organization, explanation, and attention to detail.	MPCA appreciates the comments.
N/A	Air Quality Setting Comments on the 2028 visibility projections for Boundary Waters and Voyageurs being equal or higher than current conditions.	MPCA acknowledges that this is correct and would like to clarify that the 2028 visibility projections were determined from a 2016 starting point. Meaning the RPGs established for Boundary Waters and Voyageurs do represent an improvement in visibility conditions from the baseline conditions modeled.
N/A	Source Selection Positive comments regarding the number of sources selected for analysis and considering specific suggestions from the FLMs.	MPCA appreciates the comments.
N/A	Unit Shutdowns Positive comments regarding the enforceable documents established to ensure unit shutdowns occur. Provided suggestions regarding the administrative order for Northshore Mining Company and the idling of the two power boilers, including suggestions for what should happen if the boilers restart. Requested that any future changes to administrative orders in general go through a public notice and comment.	MPCA appreciates the comments. MPCA acknowledges that not all administrative orders were not available for review during the FLM consultation period. MPCA has attempted to address the concerns regarding the restart of the Northshore Mining boilers in the administrative order included in Appendix D. MPCA appreciates the comments and understands the importance of review and comment by the FLMs and members of the public. MPCA will consider these suggestions for administrative orders moving forward. MPCA also anticipates using a rulemaking-based approach for future regional haze implementation

Section	FLM Comment	MPCA Response
		periods, which includes opportunities for public notice and comment.
2.3.5 2.6.1	Effective Controls Comments regarding the removal of emission units at taconite facilities due to the effectively controlled determination. Comments directed to U.S. EPA regarding the ongoing settlement discussions with the taconite companies regarding the Regional Haze Taconite FIP. Requested that U.S. EPA consult with the FLMs give the requirements in the Regional Haze Rule regarding FLM involvement and suggested that U.S. EPA revise the SO_2 limit down for United Taconite. Requested that MPCA identify the current FIP limits and compare to recent, measured emissions data. Suggested that air emission controls at taconite facilities should be viewed from a multi-pollutant perspective.	MPCA acknowledges the comments directed towards U.S. EPA regarding the opportunity for early consultation during the development of FIP limits versus the opportunity to comment during a public notice period when the final changes are proposed. MPCA encourages U.S. EPA to consider the FLM request for consultation regarding FIP limits. MPCA added additional detail to Section 2.3.5 regarding the current FIP limits applicable to the taconite companies and a comparison of reported emissions data for recent years. MPCA also added additional clarification to Section 2.6.1 regarding how the MPCA estimated the reductions due to the FIP limits. MPCA appreciates the suggestion to consider potential emission reduction measures from a multi-pollutant perspective. MPCA believes that is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts.
2.5.1	Four Factor Analyses Comments regarding the cost effectiveness used in the four-factor analysis process and the cost of controls at various facilities. Identified that controls below the $10,000 per ton initial screening threshold were identified by MPCA and the FLMs. Requested additional clarification regarding statements focused on the NO_X controls for Southern Minnesota Beet Sugar Cooperative. Provided a survey of pollution controls and permit limits for boilers at paper mills across Minnesota, Wisconsin, and Michigan.	MPCA added additional clarification in Section 2.5.1 regarding the effective cost threshold used in selecting controls versus the initial screening threshold. Ultimately, the controls that MPCA identified as potentially cost-effective for this regional haze implementation period cost less than approximately $7,600 per ton of pollutant reduced. MPCA also provided additional clarification to distinguish between revisions to the cost information based on facility-provided information versus revisions made by MPCA. Regarding the NO_X controls for Southern Minnesota Beet Sugar Cooperative, MPCA reiterates that there appear to be cost effective NO_X controls for this facility, but the facility disagrees with the MPCA's determination. MPCA decided to move forward with the development of this SIP submittal given that the due date of July 31, 2021, had passed. MPCA welcomes the review and input of U.S. EPA and members of the public on this topic. Regarding pollution controls at paper mills (as well as other facilities identified), MPCA believes it has met the requirements of the Regional Haze Rule in evaluating and determining the controls needed to make reasonable progress. MPCA appreciates the additional information provided and anticipates it will reexamine controls across multiple industries/sources in future regional haze implementation periods.

Section	FLM Comment	MPCA Response
	Notes of Appreciation Positive comments regarding the maintenance/continuation of the Northeast Minnesota Plan, following U.S. EPA's 2019 guidance and 2021 clarification memo, not using the uniform rate of progress as a safe harbor, not using visibility as a fifth factor to nullify the four statutory factors, and supporting the significant in-house analysis of modeling and web development.	MPCA appreciates the comments.
N/A	Wildland Fire Smoke Provided additional information regarding the historical practices of fire suppression by Native American Tribes through the intentional use of burning practices and indicated that the U.S. Forest Service will continue to work with MPCA to understand the effects of these smoke impacts on Regional Haze metrics. Suggested that future regional haze implementation periods focus primarily on control of sulfates and nitrates.	MPCA appreciates the comments and looks forward to considering this information as part of regional haze planning efforts. MPCA anticipates future conversations with the U.S. Forest Service and Minnesota Tribes regarding this topic.
2.3.4 2.5.7 2.6.2	Miscellaneous Revise the date of the Minnesota Smoke Management Plan. Add the modeled 2028 emissions to the Northeast Minnesota Plan figures to display the expected changes in emissions. Include totals and subtotals in the table that displays the long-term strategy measures reflected in the RPGs (see Table 65). Encouraged U.S. EPA to maintain fairness across the sugar beet and paper industries that exist in other states neighboring Minnesota.	MPCA updated the reference and date of the most current revision of the Minnesota Smoke Management Plan (see Section 2.3.4). MPCA added a new section to cover just the Northeast Minnesota Plan (see Section 2.5.7) and included additional discussion surrounding the additional emission reductions expected that were not included in the modeled 2028 emissions. MPCA added the totals and subtotals as requested to Table 65 (see Section 2.6.2). MPCA encourages U.S. EPA to consider the FLM request regarding sugar beet and paper industries.
	U.S. National Parks Service Comments	
2.5.1	Executive Summary General positive comments on the SIP overall regarding source selection, FLM consultation, specific details, and technical analysis overall. Disagreed in some cases with MPCA conclusions regarding cost of controls with source specific recommendations provided later and indicated other areas	MPCA appreciates the comments. MPCA added additional clarification in Section 2.5.1 regarding the effective cost threshold used in selecting controls versus the initial screening threshold. MPCA also provided additional clarification to distinguish between revisions to the cost information based on facility-provided information versus revisions made by MPCA. Additional details regarding source-specific recommendations are provided below.

Section	FLM Comment	MPCA Response
	where additional suggestions were provided in subsequent sections of the comments.	
2.3.5	Demonstration of Effective Controls Suggested that MPCA could improve the SIP with a more robust discussion surrounding effective controls for specific facilities and that they found that a four-factor analysis may have resulted in additional controls based on U.S. NPS analyses.	MPCA added additional detail to Section 2.3.5 regarding the effectively controlled determinations and a comparison of reported emissions data for recent years to support those determinations.
N/A	Retrofit Factors in Cost Analyses Provided comments regarding the retrofit factors used in cost estimates and the documentation that should be provided in support of retrofit factor used.	MPCA appreciates the detailed review and conveyed the previous comments provided by the U.S. NPS regarding retrofit factors during the review of the four-factor analyses provided by facilities. MPCA received information from the facilities regarding their choice of retrofit factor and believes the needed documentation has been provided, see the facility provided information in Appendix B.
2.5.1	Hibbing Public Utilities Commission Provided comments regarding the expected future operations of the facility, including whether to limit coal usage, and requested that MPCA include this information in the SIP if provided by the facility. Suggested that MPCA consider establishing more stringent SO_2 emission limits that are closer to the emission units' actual emission rates to prevent backsliding.	MPCA revised the discussion included for the facility in Section 2.5.1. The facility provided additional details regarding the future operations of the facility (i.e., to primarily burn wood and/or natural gas). MPCA established an administrative order with the facility to limit NO_X emissions from Boilers 1-3 that resulted in equivalent reductions that would have been achieved with installing SNCR on each boiler, see the administrative order for the facility in Appendix D. Regarding SO_2 emission rates, the facility is already subject to a more stringent SO_2 emission limit (0.90 lb/MMBtu, see Table 49) than the 4.0 lb/MMBtu limit that is referenced in the comment.
2.3.5	Minnesota Power - Boswell Energy Center Suggested that MPCA consider establishing more stringent SO_2 emission limits that are closer to the emission units' actual emission rates to prevent backsliding.	MPCA added additional detail to Section 2.3.5 regarding the effectively controlled determination for this facility which included a comparison of reported emissions data for recent years to support those determinations. The additional information shows that the facility has been implementing the existing controls and achieving a consistent emission rate over the last five years. MPCA has no reason to believe that emission rates for these emission units will increase in the future given the existing enforceable requirements shown in Table 32.
N/A	Virginia Department of Public Utilities Provided comments regarding the expected future operations of Boiler 11, identifying questions on the expected fuel and operations, and how MPCA estimated the costs of adding SCR.	MPCA estimated the costs of control equipment based on Boiler 11 operating as it has historically. Furthermore, the facility identified that NO_X emissions from Boiler 11 were highest while burning wood and are higher than if wood and natural gas combustion occurred simultaneously. If the boiler operates at a lower utilization than estimated in the cost spreadsheets, or

Section	FLM Comment	MPCA Response
	Requested that MPCA explain why Boiler 10 at the facility was not included in the four-factor analysis.	switches to only burning natural gas, the cost per ton of pollutant would only increase and remain not cost-effective. Regarding Boiler 10, MPCA did not request that the facility prepare a four-factor analysis for this emission unit. This emission unit is a natural gas-fired boiler and was not included in the four-factor analysis request due to the emissions attributed to the boiler. For reference, the maximum emissions from this boiler reported for any individual year from 2016-2020 was 12.3 tons of NO_X emissions and 0.12 tons of SO_2 emissions.
N/A	American Crystal Sugar - Crookston Suggested that MPCA consider requiring NO_X and SO_2 controls at the facility based on the information included in U.S. NPS analyses. The provided analyses adjust parameters such as retrofit factor, interest rate, control efficiency, and identified other issues of concern.	MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.
N/A	American Crystal Sugar - East Grand Forks Suggested that MPCA consider requiring NO_X and SO_2 controls at the facility based on the information included in U.S. NPS analyses. The provided analyses adjust parameters such as retrofit factor, interest rate, control efficiency, and identified other issues of concern.	MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.
N/A	Southern Minnesota Beet Sugar Cooperative Suggested that MPCA consider requiring NO_X and SO_2 controls at the facility based on the information included in U.S. NPS analyses. The provided analyses adjust parameters such as retrofit factor, interest rate, control efficiency, and identified other issues of concern.	MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update.
2.3.5	Boise White Paper Suggested that MPCA could improve the SIP with a more robust discussion surrounding effective controls for specific emission units at this facility.	MPCA added additional detail to Section 2.3.5 regarding the effectively controlled determination for this facility which included a comparison of reported emissions data for recent years to support those determinations. The additional information shows that the facility has been implementing the existing controls and achieving a

Section	FLM Comment	MPCA Response
	Suggested that MPCA consider establishing more stringent NO_X emission limits that are closer to the actual emission rates used in the four-factor analysis for Boiler 1.	consistent emission rate over the last five years. MPCA has no reason to believe that emission rates for these emission units will increase in the future given the existing enforceable requirements shown in Table 32. Regarding the NO_X emission rates used in the four-factor analysis for Boiler 1, MPCA believes it has adequately estimated the potential cost of controls while accounting for the expected emission rate of Boiler 1 by using the actual emissions rate instead of a potential emissions rate.
2.5.1	Sappi Cloquet Suggested that MPCA consider requiring NO_X controls at the facility based on the information included in U.S. NPS analyses. The provided analyses adjust parameters such as retrofit factor, interest rate, control efficiency, and identified other issues of concern.	MPCA appreciates the detailed review and comments provided on the cost estimates provided by the facility and the revisions made by MPCA. While there are multiple ways to perform a cost estimate, MPCA believes it has adequately estimated the potential cost of controls while accounting for the facility-identified site-specific considerations. As a result, MPCA did not change its determination of the controls needed to continue making reasonable progress but will consider reevaluating this facility and emission units as part of the 2025 progress report or the 2028 comprehensive update. MPCA also provided additional clarification to distinguish between revisions to the cost information based on facility-provided information versus revisions made by MPCA contained in Section 2.5.1.
2.3.5	Taconite facilities overall Provided comments regarding the appropriateness of considering the indurating furnaces as effectively controlled considering the BART determinations in U.S. EPA's Regional Haze Taconite FIP. Provided additional detail using United Taconite as an example to suggest that there might be a multi-pollutant strategy to address haze causing emissions from the facility as well as industry overall. Suggested that MPCA require all taconite facilities to conduct four-factor analyses using an integrated approach to emission control improvements.	MPCA did not exempt the taconite facilities from review during the second regional haze implementation period. MPCA believes it has provided a reasonable explanation of why these emission units were considered effectively controlled for this regional haze implementation period. MPCA added additional detail to Section 2.3.5 regarding the effectively controlled determinations and a comparison of reported emissions data for recent years to support those determinations. MPCA appreciates the suggestion to consider potential emission reduction measures from a multi-pollutant perspective. MPCA believes that is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts.

4.4. Checklist

In its August 2019 Guidance, U.S. EPA provides a table in Appendix D of the guidance document that provides additional detail on steps in developing a Regional Haze SIP. The MPCA has recreated the table from U.S. EPA's guidance to serve as a checklist and verification that all requirements of the Regional Haze Rule have been met and are documented within this SIP document.

Table 83. August 2019 Guidance, Appendix D - Detailed steps in developing a Regional Haze SIP

Applicability	Step or Task	Relevant 2017 Regional Haze Rule Provision(s)	Section in Minnesota's SIP
1 All states.	Take inventory of information resources available for SIP development.	Not explicitly addressed.	1.6
2 All states.	Determine Class I areas in other states that may be affected by emission sources in the state.	40 CFR § 51.308(f)(2)	2.2.1
3 All states.	Determine which other states have sources that may be reasonably anticipated to affect in-state Class I areas.	40 CFR § 51.308(f)(2)(ii)	2.2.3
4 All states.	Consult with these states, through multi-state organizations and directly.	40 CFR § 51.308(f)(2)(ii)	2.9.1
5 All states.	Consult with FLMs for all in-state Class I areas and affected out-of-state Class I areas on an ongoing basis.	40 CFR § 51.308(i)(4)	2.9.2
6 States with Class I areas.	Analysis of visibility monitoring data Determine the baseline (2000-2004) visibility condition and the current visibility condition (as defined in section 51.301) for the 20 percent most anthropogenically impaired days and for the 20 percent clearest days, for each in-state Class I area. This must be done based on using available monitoring data. Determine the natural visibility condition (as defined in section 51.301) for the 20 percent most anthropogenically impaired days and for the 20 percent clearest days, for each in-state Class I area. This must be done based on using available monitoring data and appropriate data analysis techniques. Determine the difference between the baseline period visibility condition and the current visibility condition, for both sets of days. This is the "actual progress made towards the natural visibility condition since the baseline period." Determine the difference between the average visibility condition in the period of 2003-2007 and the average visibility condition for each subsequent 5-year period, up to and including the 5-year period that determines current visibility conditions, for both sets of days. This is the "actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions."	40 CFR § 51.308(f)(1)	2.1.1
6 States with Class I areas.	Determine the difference between the current visibility conditions and natural visibility conditions, for both sets of days.		2.1.5
7	(Optional) Develop current extinction budgets for each Class I area.	Not explicitly addressed.	NA

Applicability	Step or Task	Relevant 2017 Regional Haze Rule Provision(s)	Section in Minnesota's SIP
States with Class I areas.			
8 All states.	Identify significant future trends in emissions.	40 CFR § 51.308(f)(2)(iv)(A)	2.6
9 All states.	(Optional) Conduct source apportionment modeling and/or review available results from such modeling by other parties.	Not explicitly addressed.	2.2.3
10 All states.	(Optional) Conduct modeling to predict visibility levels for the 20 percent most impaired and 20 percent clearest days as of the end of the implementation period assuming already adopted emissions controls and/or review available results from such modeling by other parties. A comparison of these projected levels to current visibility conditions is a factor that may be considered in the source selection step (step 12 on this list).	Not explicitly addressed	2.7
11 All states.	(Optional) Estimate baseline visibility impacts for source selection purposes.	Not explicitly addressed.	2.4.7
12 All states.	Select sources for analysis of control measures.	40 CFR § 51.308(f)(2)(i)	2.3
13 All states.	Identify emission control measures to be considered for these sources.	40 CFR§ 51.308(f)(2)(i)	2.4.1
14 All states.	Characterize the four factors for these sources and measures.	40 CFR § 51.308(f)(2)(i)	2.4.3 - 2.4.6
15 All states.	(Optional) Quantify visibility benefits for these sources and measures.	Not explicitly addressed.	NA
16 All states.	Consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources.	40 CFR § 51.308(f)(2)(i)	2.3
17 All states.	Document the criteria used to determine the sources or groups of sources that have been evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in the long-term strategy (LTS).	40 CFR § 51.308(f)(2)(i)	2.3.6
18 All states.	Document the technical basis, including information on the four factors and modeling, monitoring, and emissions information on which the state is relying to determine the emission reductions from anthropogenic sources in the state that are necessary for achieving reasonable progress towards natural visibility conditions in each Class I area it affects.	40 CFR § 51.308(f)(2)(iii)	2.5
19 All states.	Identify the emissions information on which the state's strategies are based and explain how this information meets the Regional Haze Rule's requirements regarding the year(s) represented in the information, i.e., tie to the submission of information to the NEI.	40 CFR § 51.308(f)(2)(iii)	2.4.2
20 All states.	Consult with those states that have emissions that are reasonably anticipated to contribute to visibility impairment in the in-state Class I areas to develop	40 CFR § 51.308(f)(2)(ii)	2.9.1

Applicability	Step or Task	Relevant 2017 Regional Haze Rule Provision(s)	Section in Minnesota's SIP
	coordinated emission management strategies containing the emission reductions necessary to make reasonable progress. This consultation could include the exchange of relevant portions of analyses of control measures and associated technical information.		
21 All states.	Include in the SIP all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.	40 CFR § 51.308(f)(2)(ii)(A)	N/A
22 All states.	Consider the emission reduction measures identified by other states for their sources as being necessary to make reasonable progress in the Class I area.	40 CFR § 51.308(f)(2)(ii)(B)	N/A
23 All states.	Include in the SIP a description of the actions taken to resolve any disagreements with other states regarding measures that are necessary to make reasonable progress at jointly affected Class I areas.	40 CFR § 51.308(f)(2)(ii)(C)	2.9.1
24 All states.	Consider emission reductions due to ongoing air pollution control programs, including measures to address RAVI.	40 CFR § 51.308(f)(2)(iv)(A)	2.3.4
25 All states.	Consider measures to mitigate the impacts of construction activities.	40 CFR § 51.308(f)(2)(iv)(B)	2.3.4
26 All states.	Consider source retirement and replacement schedules.	40 CFR § 51.308(f)(2)(iv)(C)	2.4.6
27 All states.	Consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs. After consideration of basic smoke management practices, states have the option to include the practices into their SIP submittal, but it is not required.	40 CFR § 51.308(f)(2)(iv)(D)	2.3.4
28 All states.	Consider the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS.	40 CFR § 51.308(f)(2)(iv)(E)	2.6.2
29 All states.	Select measures for inclusion in the LTS.	40 CFR § 51.308(f)(2)	2.6.1
30 All states.	Set emission limits, averaging periods and monitoring and record keeping requirements.	40 CFR § 51.308(f)(2) - opening text	2.5.6
31 All states.	Set compliance deadlines.	40 CFR § 51.308(f)(2) - opening text	2.5.6
32 States with Class I areas.	Project the 2028 RPGs for the 20 percent most anthropogenically impaired and 20 percent clearest days.	40 CFR § 51.308(f)(3)	2.6.2
33 All states.	URP Glidepath Check		2.7
33A	Determine the URP using the baseline period visibility condition value and the natural visibility conditions	40 CFR § 51.308(f)(1)(vi)	2.7

Applicability	Step or Task	Relevant 2017 Regional Haze Rule Provision(s)	Section in Minnesota's SIP
States with Class I areas.	value for the 20 percent most anthropogenically impaired days. The URP may be adjusted for impacts from anthropogenic sources outside the U.S. and from certain types of prescribed fires, subject to U.S. EPA approval as part of U.S. EPA's action on the SIP submission.		
33B All states.	Compare 2028 RPG for the 20 percent most anthropogenically impaired days to the 2028 point on the URP glidepath. If the 2028 point is above the glidepath demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the state that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the LTS.	40 CFR § 51.308(f)(3)(ii)	2.6.2
33C All states.	If the 2028 RPG for the 20 percent most anthropogenically impaired days is above the 2028 point on the URP glidepath, Calculate the number of years it would take to reach natural conditions at the rate of progress provided by the SIP for the implementation period.	40 CFR § 51.308(f)(3)(ii)(A)	NA
34 States with Class I areas.	Compare the 2028 RPG for the 20 percent clearest days to the 2000-2004 conditions for the same days, and strengthen the LTS if there is degradation. Also, compare the 2028 RPG for the 20 percent most anthropogenically impaired days to the 2000-2004 conditions for the same days, and strengthen the LTS if the RPG does not show an improvement.	40 CFR § 51.308(f)(3)(i)	2.7
35 States with Class I areas.	Submit a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all Class I areas within the state.	40 CFR § 51.308(f)(6)	2.8.4
36 States with Class I areas.	Provide for the establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals to address regional haze for all Class I areas within the state are being achieved.	40 CFR § 51.308(f)(6)(i)	2.8.4
37 States with Class I areas.	Provide for procedures by which monitoring data and other information are used in determining the contribution of emissions from within the state to regional haze visibility impairment at Class I areas both within and outside the state.	40 CFR § 51.308(f)(6)(ii)	2.8.4
38 States without a Class I area.	For a state with no Class I areas, provide for procedures by which monitoring data and other information are used in determining the contribution of emissions from within the state to regional haze visibility impairment at Class I areas in other states.	40 CFR § 51.308(f)(6)(iii)	N/A
39	Provide for reporting of all visibility monitoring data to the Administrator at least annually for each Class I area	40 CFR § 51.308(f)(6)(iv)	2.8.4

Applicability	Step or Task	Relevant 2017 Regional Haze Rule Provision(s)	Section in Minnesota's SIP
States with Class I areas.	in the state. To the extent possible, the state should report visibility monitoring data electronically.		
40 All states.	Provide for a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The inventory must include emissions for the most recent year for which data are available, and estimates of future projected emissions. The state must also include a commitment to update the inventory periodically.	40 CFR § 51.308(f)(6)(v)	2.8.5
41 States with Class I areas.	Provide other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility.	40 CFR § 51.308(f)(6)(vi)	2.8.4
42 All states.	Commit to submit the January 31, 2025, progress report.	40 CFR § 51.308(f) opening text	1.6
43 All states.	Offer an in-person consultation meeting with responsible FLMs at a point early enough in the state's policy analyses of its LTS emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the state's decisions on the LTS.	40 CFR § 51.308(i)(2).	2.9.2
44 All states.	Include in the SIP submission a description of how the state addressed any comments provided by the FLMs.	40 CFR § 51.308(i)(3)	4.3