United States Department of the Interior

NATIONAL PARK SERVICE
601 Riverfront Drive
Omaha, NE 68102

1.A.2 (MWR-NRSS)

October 3, 2022

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

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

Dear Mr. Bouchareb:

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

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

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

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

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

Sincerely,

HERBERT
FROST

Digitally signed by HERBERT FROST
Date: 2022.09.30 15:41:56 -05'00'

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

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

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

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

October 3, 2022

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1 Executive Summary

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

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

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

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

2 Overarching Feedback

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

2.1 Four-factor Analysis Screening - Demonstration of Effective Controls

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

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

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

2.2 Retrofit Factors in Cost Analyses

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

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

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

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

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

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

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

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

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

2.3 Control Efficiency and Outlet Emissions

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

For SCR, the CCM advises:

> *In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other NOx controls such as LNB or FGR that achieve relatively low emissions on their own. The outlet concentration from SCR on a utility boiler is rarely less than 0.04 lb/million British thermal units (MMBtu)*

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

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

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

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

2.4 Control Equipment Life

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

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

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

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

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

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

2.5 Unsupported Costs

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

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

2.6 Missing and Incomplete Analyses/Unsupported Control Determinations

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

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

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

2.7 Cost Effectiveness Thresholds

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

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

With respect to the first implementation period MPCA says that:

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

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

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

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

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

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

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

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

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

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

3 Electric Generating Facilities – Four-Factor Feedback

3.1 Hibbing Public Utilities Commission

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

3.2 Minnesota Power–Boswell Energy Center

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

4 Sugar beet Processing Facilities – Four-Factor Feedback

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

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

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

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

4.1 American Crystal Sugar – Crookston[2]

4.1.1 Summary of NPS Recommendations for American Crystal Sugar–Crookston

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

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

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

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

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

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

4.1.2 Facility Characteristics

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

4.1.3 SO_2 Four-factor Analysis

Control Selection & Efficiency

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

Control Selection & Efficiency

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

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

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

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

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

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

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

Statutory Factor 1: Cost of Compliance

In its 2022 submittal, HDR states:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Statutory Factor 2: Time Necessary for Compliance

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

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

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

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

Statutory Factor 4: Remaining Useful Life

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

4.1.4 NO_x Four-factor Analysis

Control Selection & Efficiency

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

Statutory Factor 1: Cost of Compliance

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

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

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

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

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

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

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

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

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

Statutory Factor 2: Time Necessary for Compliance

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

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

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

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

Statutory Factor 4: Remaining Useful Life

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

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

4.1.5 NPS Conclusions and Recommendations for American Crystal Sugar – Crookston

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

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

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

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

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

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

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

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

4.2 American Crystal Sugar–East Grand Forks[7]

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

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

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

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

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

4.2.2 Facility Characteristics

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

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

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

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

4.2.3 SO_2 Four-factor Analysis

Control Selection & Efficiency

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

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

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

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

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

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

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

Statutory Factor 1: Cost of Compliance

In its 2022 submittal, HDR states:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Statutory Factor 2: Time Necessary for Compliance

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

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

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

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

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

Statutory Factor 4: Remaining Useful Life

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

4.2.4 NO_x Four-factor Analysis

Control Selection & Efficiency

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

Statutory Factor 1: Cost of Compliance

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

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

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

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

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

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

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

Statutory Factor 2: Time Necessary for Compliance

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

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

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

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

Statutory Factor 4: Remaining Useful Life

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

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

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

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

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

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

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

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

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

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

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

4.3 Southern Minnesota Beet Sugar Cooperative[13]

4.3.1 Summary of NPS Recommendations for Southern Minnesota Beet Sugar Cooperative

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

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

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

4.3.2 Facility Characteristics

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

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

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

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

4.3.3 Overarching Cost Issues

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

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

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

4.3.4 SO_2 Four-factor Analysis

Control Selection & Efficiency

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

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

SDA and DSI SO_2 Control Efficiency Basis

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

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

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

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

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

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

Control Equipment Life

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

Spray Dry Absorbers (SDA)

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

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

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

DRY SORBENT INJECTION (DSI) AND BAGHOUSES

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

Statutory Factor 1: Cost of Compliance

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

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

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

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

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

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

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

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

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

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

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

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

Statutory Factor 2: Time Necessary for Compliance

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

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

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

Statutory Factor 4: Remaining Useful Life

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

4.3.5 NO_x Four-factor Analysis

Control Efficiency

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

Statutory Factor 1: Cost of Compliance

Basis for the selected retrofit factor

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

Basis and Cost for SCR Reheat

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

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

SCR Catalyst and Equipment Life Basis

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

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

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

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

SMBSC also replied (July 23, 2021):

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

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

NPS Estimated Cost of Compliance for SNCR

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

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

Significant Issues regarding SNCR Cost-Effectiveness:

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

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

NPS Estimated Cost of Compliance for SCR

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

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

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

Significant Issues regarding SCR Cost-Effectiveness:

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

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

Statutory Factor 2: Time Necessary for Compliance

SCR operation typically requires four to five years after SIP approval, while SNCR may take up to two years.

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

When evaluating statutory factor 3, SMBSC raises several potential concerns with respect to SNCR and SCR including fuel consumption and energy use. The energy impacts mentioned are most properly accounted for when analyzing statutory factor 1, Cost of Compliance.

Statutory Factor 4: Remaining Useful Life

The CCM recommends 20- 25-year life for SCR on industrial boilers and 20 years for SNCR on industrial boilers unless limited by a federally-enforceable condition. NPS believes that 25 years is an appropriate estimate for the life of an SCR system on a boiler that only operates seasonally.

4.3.6 NPS Conclusions and Recommendations Southern Minnesota Beet Sugar Cooperative

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

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

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

- The addition of DSI (with trona) is cost-effective for SO_2 emission reductions with or without addition of a new baghouse.
- The addition of SDA/CDS is also cost-effective and would provide a superior level of SO_2 emission control.
- The addition of SNCR is a cost-effective option for reducing NO_x emissions.

- The addition of SCR is also cost-effective and would provide a superior level of NO_x emission control.

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

In its "Table 51. NO_x control information (MPCA revision)" MPCA estimates that SNCR could remove 447 ton/yr of NO_x at $2,942/ton, and that SCR could remove 832 ton/yr of NO_x at $5,986/ton. Although the cost-effectiveness of both SNCR and SCR (as estimated by MPCA) are below MPCA's $7,600/ton threshold, SCR does not appear in MPCA's "Table 58. Southern Minnesota Beet Sugar Cooperative - Control measure evaluation." Without explanation, MPCA has omitted further consideration of SCR in its Table 58 and instead states:

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

MPCA appears to be depending upon SMBSC to agree to addition of SNCR with no further consideration of the more-efficient (cost-effective) SCR technology.

In conclusion, based on the four factors, the NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. The SDA/CDS option could remove 700 tons/year of SO_2 at an annual cost of $4.5 million for a cost-effectiveness value of less than $6,500/ton. The NPS estimates that addition of SCR could reduce annual NO_x by about 800 tons at an annual cost of $3–$5 million resulting in a cost-effective strategy of $3,900–$5,400/ton of NO_x removed.

5 Paper Manufacturing – Four-Factor Feedback

MPCA conducted four-factor analyses for two paper mills with the emissions shown below.

Table 12. MPCA Table 28. Q/d Analysis Emissions Data (tons/yr)

MPCA Table 28. Q/d Analysis emissions data (tons/yr)	NO_x	SO_2
Sappi Cloquet LLC	1,420.65	82.88
Boise White Paper LLC - Intl Falls	802.76	33
Totals	2,223.41	115.88

MPCA is not requiring any emission reductions from these facilities.

5.1 Sappi Cloquet LLC[16]

5.1.1 Summary of NPS Recommendations for Sappi Cloquet LLC

NPS review of the four-factor analysis conducted for Sappi Cloquet LLC supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

With respect to the NO_x evaluation on Power Boiler #9, NPS review finds that:

- Addition of SNCR is cost-effective, and
- Addition of SCR is also cost-effective and represents greater emission control.

The NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. NPS estimates indicate that addition of SCR to Boiler 9 could reduce annual NO_x by almost 300 tons/year at an annual cost of about $2 million resulting in a cost-effective strategy of about $6,500/ton of NO_x removed. By requiring implementation of identified controls MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

5.1.2 Facility Characteristics

Sappi Cloquet LLC (Sappi) is a Kraft pulp and paper mill that manufactures paper pulp, dissolving wood pulp, and fine coated paper. The facility is located near Cloquet, MN, about 175

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

km south of Voyageurs National Park, a Class I area administered by the NPS. The two emission units included in MPCA's request for information are:

- Power Boiler #9 (2016 NO_X emissions = 434 ton/yr.)
- Recovery Boiler #10 (2016 NO_X emissions = 704 ton/yr.)

It appears that these two emission units account for about 80% of mill NO_X emissions.

NPS supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled with quaternary air and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

5.1.3 NO_x Four-factor Analysis

Control Selection & Efficiency

Power Boiler #9 is a stoker grate design that burns primarily hog fuel (biomass), utilizes natural gas as a startup/supplemental fuel, is a backup combustion source for non-condensible gases, and is permitted to burn distillate oil. Based on the primary fuel use and the design of Power Boiler #9, Low-NO_x Burners (LNB) were not considered in the four-factor analysis because:

- LNB for solid fuels (like the ones at coal fired power plants) typically utilize dry solid fuel which is pulverized to a fine powder in a mill and fed pneumatically into the burners. This allows staging of air and fuel in the combustion process in order to reduce NO_x emissions. This technology is not feasible for the stoker grate hog fuel boiler at Sappi.
- LNB for natural gas and/or distillate oil are technically feasible options, but the hog fuel boiler at Sappi burns primarily hog fuel (biomass). Thus, installing LNB for natural gas and/or distillate oil would have a minor impact on NO_x emissions and therefore was not further considered in the four-factor analysis.

Based on this information, the technologies that were considered in the four-factor analysis are SCR and SNCR. The NPS supports this determination of appropriate NO_x controls for consideration.

Statutory Factor 1: Cost of Compliance

The table below shows the SNCR and SCR costs estimated by MPCA and the NPS for Sappi. All cost-effectiveness values are below $10,000/ton, and NPS estimates that the cost-effectiveness of adding SCR is below MPCA's $7,600/ton acceptance threshold.

Table 13. NPS estimated NO_x control costs for Sappi Cloquet power boiler 9 compared to MPCA estimates

Sappi Boiler 9				
Control Technology	**SNCR**		**SCR**	
	NPS	**MPCA**	**NPS**	**MPCA**
Capacity (mmBtu/hr)	430	430	430	430
Retrofit factor	1	1	1	1.33
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$ 6,068,270	$ 6,068,270	$ 22,651,621	$ 29,945,905
Interest rate (%)	3.50	3.50	3.50	3.50
Control Equipment Life (yr)	20	20	25	25
Capital Recovery Cost	$ 427,206	$ 427,206	$ 1,374,953	$ 1,817,716
Indirect Cost/Fixed O&M	$ 429,937	$ 429,937	$ 1,378,847	$ 1,822,048
Total System Capacity Factor	0.631	0.631	0.631	0.631
Catalyst Life (hr)			20,000	20,000
Catalyst Replacement Cost Method			1	1
Catalyst Replacement Cost			$ 199,786	$ 194,561
Direct Cost/Variable O&M	$ 168,063	$ 312,950	$ 485,705	$ 514,973
Total Annual Cost	$ 598,000	$ 742,887	$ 1,864,552	$ 2,337,020
Uncontrolled NOx Emissions (Tons/yr)	347	347	347	347
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.29	0.29	0.29	0.29
NOx Removal Efficiency (%)	21	25	83	80
Controlled NOx Emission Rate (lb/mmbtu)	0.23	0.22	0.05	0.06
Tons Removed	74	87	288	278
Cost-Effectiveness	$ 8,115	$ 8,562	$ 6,483	$ 8,418

Significant Issues regarding Cost-Effectiveness:

- A retrofit factor (1.33) greater than the CCM default value of 1.0 (which inherently represents a 25% increase over a "greenfield" application) was not justified. The CCM advises that:
  - If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate. According to the CCM, "You must document why a retrofit factor of "__" is appropriate for the proposed project." The MPCA retrofit factor represents a 66% increase versus a "greenfield" estimate.
- The CCM default for catalyst life is 16,000 – 24,000 hours; NPS used the MPCA 20,000-hour estimate for this application to a woodwaste-fired boiler.
- It is likely that MPCA has overestimated SNCR control efficiency and the resulting Direct Operating Costs and Tons Removed. It also appears that MPCA has overestimated the Normalized Stoichiometric Ratio (NSR) and ammonia use

for ammonia injection. NPS recommends application of the relationship shown in CCM Figure 1.1c and the CCM workbook default NSR = 1.05.
- It is likely that MPCA has underestimated SCR control efficiency and the resulting Direct Operating Costs and Tons Removed. The CCM advises that SCR can achieve emissions as low as 0.04 lb/mmbtu (and up to 90% control). NPS analyses used 0.05 lb/mmbtu (83% control) to be conservative.

The NPS estimates that addition of SNCR could reduce annual NO_x by over 70 tons at an annual cost of about $0.6 million resulting in a cost-effective strategy of about $8,100/ton of NO_x removed.

NPS estimates that addition of SCR could reduce annual NO_x by almost 300 tons at an annual cost of about $2 million resulting in a cost-effective strategy of about $6,500/ton of NO_x removed; this is below the MPCA's $7,600/ton acceptance threshold.

Statutory Factor 2: Time Necessary for Compliance
SCR operation typically requires four to five years after SIP approval, while SNCR may take up to two years.

Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts
Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life
The CCM recommends 20–25-year life for SCR and 20 years for SNCR on industrial boilers unless limited by a federally-enforceable condition. NPS agrees with MPCA's estimates of 20 years for SNCR and 25 years for SCR.

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

5.1.4 NPS Conclusions and Recommendations Sappi Cloquet LLC
NPS supports MPCA findings that:

- Recovery Boiler #10 is effectively controlled and can be screened from four-factor evaluation.
- Projected 2028 emissions of SO_2 from Power Boiler #9 are too low to warrant four-factor evaluation of DSI or SDA emission controls from that unit.

For NO_x evaluation on Power Boiler #9, NPS review finds that:

- Addition of SNCR is cost-effective, and
- Addition of SCR is also cost-effective and represents greater emission control.

The NPS recommends that MPCA evaluate statutory factor two, the *Time Necessary for Compliance*, for addition of SNCR and SCR for Power Boiler #9. Review of statutory factors three and four finds no unusual *Energy and Non-Air Quality Environmental Impacts* related to SNCR or SCR and *Remaining Useful Life* is not an issue.

The NPS recommends that MPCA require the addition of cost-effective control strategies that provide the greatest emission reductions. NPS estimates indicate that addition of SCR to Boiler 9 could reduce annual NO_x by almost 300 tons/year at an annual cost of about $2 million resulting in a cost-effective strategy of about $6,500/ton of NO_x removed. By requiring implementation of identified controls, MPCA will be reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

5.2 Boise White Paper

5.2.1 Summary of NPS Recommendations for Boise White Paper

NPS review of the four-factor analysis conducted for Boise White Paper (Boise) finds that, as a result of screening Boiler 2 and the Recovery Furnace, almost 688 annual tons of NO_x were not evaluated at this facility. The NPS recommends that MPCA require a four-factor evaluation of NO_X emission control opportunities for Boiler 2 and the Recovery Furnace

For Boiler 1, the NPS recommends that MPCA adjust the permitted NO_x emissions rate to more closely reflect the emission rate evaluated. If the currently permitted limit is considered, SCR may be cost effective.

For Boiler 2, the NPS estimates that addition of SCR may be very cost-effective and recommends that MPCA require a four-factor analysis for this emission unit.

5.2.2 Facility Characteristics

Boise White Paper (Boise) is wholly owned by Packaging Corporation of America (PCA) and is located in International Falls, 17 km west of Voyageurs National Park, a Class I area administered by the National Park Service. The facility is an integrated Kraft pulp and paper mill that produces commodity and specialty paper. The three emission units included in MPCA's request for information are:

- Boiler 1 (2016 NO_X emissions = 73 ton/yr.)
- Boiler 2 (2016 NO_X emissions = 366 ton/yr.)
- Recovery Furnace (2016 NO_X emissions = 322 ton/yr.)

It appears that these three emission units account for about 95% of mill NO_X emissions. In total, as a result of screening Boiler 2 and the Recovery Furnace, about 688 annual tons of NO_x were not evaluated at this facility.

Facility-wide SO_2 emissions were 33 tons.

Boise Boiler #1 was originally commissioned as a coal-fired boiler and has been converted to only burn natural gas. The boiler produces steam to generate electricity and provide heat for other processes at the plant. Exhaust from the sludge dryer may also vent to Boiler #1. The boiler is also a backup combustion source for non-condensable gases (NCG) which are the exhaust gases from the pulp digestion and black liquor solids (BLS) evaporation processes. The amount of NCG burned in Boiler #1 is limited by the facility air permit. Good combustion practices are utilized for Boiler #1 through a combination of several efforts, including control strategy, boiler monitoring, and training.

5.2.3 Boiler #1 NO_x Four-factor Analysis

Control Selection

Three types of NO_x emission controls were evaluated for Boise Boiler 1:

- LNB/OFA + FGR
- SNCR
- SCR

The SNCR analysis is not included in MPCA SIP Table 44 but was included in NPS review.

Statutory Factor 1: Cost of Compliance

MPCA presented the analyses shown in its Table 51 below.

Table 14. Minnesota draft SIP Table 51. NO_x control information (MPCA revision)

Facility	Emission Unit	Control Measure	Emission Reduction (tpy)	Capital Costs ($)	Annual Costs ($)	Cost Effectiveness ($/ton)
Boise White Paper	Boiler 1	LNB/OFA + FGR	58	$11,144,531	$1,557,544	$26,649
		SCR	66	$8,031,851	$905,022	$13,783

In addition, MPCA provided an analysis of SNCR using methods developed by EPA in its Control Cost Manual (CCM) and determined that SNCR could reduce NO_x emissions by 38 tons/yr at an annual cost of about $250,000 for a cost-effectiveness value of just over $6,600/ton of NO_x removed, which is below the MPCA $7,600/ton cost-effectiveness threshold.

The NPS applied the CCM SNCR and SCR workbooks with the parameters shown below, including application of the relationship provided in CCM SNCR Figure 1.1c to estimate SNCR control efficiency. NPS analyses assumed that SCR on this natural gas-fired boiler would have a 25-year equipment life and a 24,000-hour catalyst life and could achieve 85% control.

Table 15. Comparison of NPS and MPCA Cost Calculations for Boise Boiler #1

Emission Unit	**Boiler #1**			
	NPS	**MPCA**	**NPS**	**MPCA**
Control Technology	**SNCR**		**SCR**	
Capacity (mmBtu/hr)	398	398	398	398
Retrofit factor	1	1	1	1
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$ 2,522,567	$ 2,658,260	$ 8,031,851	$ 8,031,851
Interest rate (%)	3.50	3.50	3.50	3.50
Control Equipment Life (yr)	20	20	25	20
Capital Recovery Cost	$ 177,589	$ 187,141	$ 487,533	$ 565,442
Indirect Cost/Fixed O&M	$ 178,724	$ 188,338	$ 490,542	$ 568,451
Catalyst Life (hours)			24,000	20,000
Direct Cost/Variable O&M	$ 59,483	$ 61,518	$ 285,762	$ 336,571
Total Annual Cost	$ 238,207	$ 249,856	$ 776,305	$ 905,022
Uncontrolled NOx Emission Rate (lb/mmBtu)	0.13	0.13	0.13	0.13
Uncontrolled Tons	95	95	94	95
NOx Removal Efficiency (%)	19	40	85	70
Controlled NOx Emission Rate (lb/mmbtu)	0.11	0.08	0.02	0.04
Tons Removed	18	38	79	66
Cost-Effectiveness	$ 13,122	$ 6,608	$ 9,781	$ 13,783

NPS estimates that addition of SCR could reduce NO_X emissions by almost 80 tons/yr at a annual cost of $0.8 million at $9,800/ton. While this cost-effectiveness value is above the MPCA threshold, it is below the $10,000/ton threshold used by CO, NV, and OR. Statutory Factor 2: Time Necessary for Compliance

Installation of SNCR typically requires up to two years while time necessary for compliance for SCR is typically four to five years after SIP approval. Statutory Factor 3: Energy and Non-Air Quality Environmental Impacts

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

MPCA used a 20-year life for SNCR and SCR.

Boise Boiler #2 was originally commissioned as a coal-fired boiler This emission unit is a stoker grate design which produces steam to generate electricity and provide heat for other processes at the plant. The boiler burns primarily hog fuel (biomass which is primarily bark and wood refuse from the facility de-barking process) and is also permitted to burn wastewater treatment plant sludge, paper, and natural gas. The boiler is also a backup combustion source for NCG. The amount of NCG burned in Boiler #2 is limited by the facility air permit. Particulate matter emissions from the power boiler are controlled by multiclones and a high-efficiency electrostatic precipitator (ESP). Boiler #2 does not have add-on NO_X controls but does use staged and overfire air to manage the generation of NO_X The boiler does not have add-on SO_2 controls but burns low sulfur fuels and the wood ash provides some dry scrubbing of SO_2 when NCGs are burned concurrently. This boiler appears to be very similar to Boiler 9 at Sappi Cloquet for which MPCA required a four-factor NO_X control analysis.

5.2.4 Boiler #2 NO_x Four-factor Analysis

MPCA screened Boiler 2 from four-factor analysis based on a 2013 BACT analysis and the presence of a more stringent NO_x emissions limits than found in a review of permit limits for similar sources.

However, NPS has reviewed three other hogged fuel boilers similar to Boiler #2 at paper mills, including the Sappi mill in Cloquet, MN where SNCR and SCR were evaluated by the state for NO_x reductions. Two of those boilers (PCA @ 0.19 lb/mmBtu in Wallula, WA and Nippon Dynawave @ 0.23 lb/mmBtu in Longview, WA) have NO_x emission rates that are lower than the 0.25 lb/mmBtu NO_X emission rate for Boiler 2 at Boise White.

In its July 2021 clarification memo, EPA advised that states must show why additional emission reductions are not necessary to make reasonable progress. Section 2.3 addressed the analytical expectations for "effectively controlled" determinations:

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

MPCA has not demonstrated that conducting a four-factor analysis would be a "futile exercise." In fact, NPS will show that post-combustion NO_X controls on Boiler 2 could be cost-effective. The NPS recommends that MPCA or require a four-factor evaluation of NO_X these emission control opportunities.

Statutory Factor 1: Cost of Compliance

In the absence of a four-factor analysis by MPCA, NPS used information from the draft SIP.

- Based upon CCM Figure 1.1c, SNCR is estimated to reduce NO_x emissions by 20% from a baseline emission rate of 0.25 lb/mmBtu.
- SCR is assumed to be able to achieve 80% NO_X reduction down to 0.05 lb/mmBtu for this woodwaste-fired boiler.
- An SCR catalyst life = 20,000 hours for this woodwaste-fired boiler.

Table 16. NPS Control Cost Estimates for Boise Boiler #2

Emission Unit	**Boiler #2**	
Control Technology	**SNCR**	**SCR**
Capacity (mmBtu/hr)	400	400
Retrofit factor	1	1
CEPCI	607.5	607.5
Capital Cost	$ 3,964,043	$ 21,253,112
Interest rate (%)	3.50	3.50
Control Equipment Life (yr)	20	25
Capital Recovery Cost	$ 279,069	$ 21,253,112
Indirect Cost/Fixed O&M	$ 280,852	$ 1,290,064
Catalyst Life (hours)		20,000
Direct Cost/Variable O&M	$ 110,882	$ 1,293,967
Total Annual Cost	$ 391,735	$ 1,646,615
Uncontrolled NOx Emission Rate (lb/mmbtu)	0.25	0.25
Uncontrolled Tons	401	401
NOx Removal Efficiency (%)	22	80
Controlled NOx Emission Rate (lb/mmbtu)	0.20	0.05
Tons Removed	88	321
Cost-Effectiveness	$ 4,462	$ 5,132

NPS analysis determined that SNCR could reduce NO_x emissions by 88 tons/yr at an annual cost of about $392,000 for a cost-effectiveness value of almost $4,500/ton of NO_x removed.

For SCR, NPS determined that SCR could reduce NO_x emissions by 320 tons/yr at an annual cost of $1,646,000 for a cost-effectiveness value of about $5,100/ton of NO_x removed.

Statutory Factor 2: Time Necessary for Compliance

Installation of SCR typically requires four-to-five years.

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

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

MPCA used a 20-year life for SNCR and for SCR. The CCM recommends 20 – 25 years for SCR; NPS analyses assumed 25 years for this woodwaste-fired boiler.

Recovery Furnace: This emission unit burns strong BLS that are generated in the kraft pulp mill chemical recovery process. Weak BLS, which is generated as part of the pulping and washing processes, are concentrated in evaporators to make strong BLS. The strong BLS is then charged to the Recovery Furnace where the organic portion of the BLS is burned to produce steam to generate electricity and provide heat for other processes at the plant. The cooking chemicals collect as molten smelt at the bottom of the boiler. The amount of BLS burned in the Recovery

Furnace is limited by the facility air permit. The Recovery Furnace is a primary source of all criteria pollutant emissions, as well as sulfuric acid (H2SO4), total reduced sulfur (TRS), and Hazardous Air Pollutants (HAP). Particulate matter emissions from the Recovery Furnace are controlled by a high-efficiency ESP. The Recovery Furnace does not have add-on NOX controls but does use staged air injection to manage the generation of NOX.

MPCA screened the Recovery Furnace from four-factor analysis based on a 2013 BACT analysis and the presence of a more stringent NO_x emissions limits than found in a review of permit limits for similar sources.

NPS notes that potentially more-effective quaternary air combustion controls are in use (at the Sappi Cloquet mill in Minnesota) to reduce NO_X from the Recovery Furnace. While the recovery furnace uses staged air combustion to manage the generation of NO_x, it is not clear if that includes quaternary air.[17] If not, the NPS recommends that MPCA investigate its addition.

5.2.5 NPS Conclusions and Recommendations Boise White Paper

MPCA's Table 33 shows that Boise emitted 803 tons of NO_x. Of this total, only 73 tons of NO_x are attributed to Boiler #1, the only unit selected for four-factor evaluation. MPCA Table 33 shows that Boiler #2 has NO_x emissions of 401 tons/yr and that the Recovery Furnace has NO_x emissions of 323 tons/yr. Emissions from each of these units is several times greater than the emissions that were evaluated.

- For Boiler #1 the NPS has determined that SCR may be cost effective relative to the $10,000/ton threshold used by CO, NV, and OR.
- In the absence of a four-factor analysis and based upon available information, the NPS estimates that addition of SCR to Boiler #2 may be very cost-effective. The NPS recommends that MPCA require a four-factor analysis for this emission unit.
- The NPS also recommends that MPCA evaluate the addition of quaternary air to the Recovery Furnace (if it is not already so-equipped).

[17] SUN BIO MATERIAL (U.S.) COMPANY, PSD PERMIT APPLICATION, November 2018: The most widely used combustion modification approach in recovery boilers is commonly referred to as "quaternary air/staged combustion." This technology involves four stages of combustion air supplied at successively higher points in the body of the furnace. Quaternary Air/Staged Combustion minimizes NOx emissions by maintaining the minimum combustion temperature possible at each successive stage in the furnace to combust the black liquor solids while maintaining high sulfur reduction efficiencies, good bed stability, and uniform velocities after the furnace to minimize high temperatures and fouling. Primary air is used for bed stability, efficient carbon burnout, and high sulfur reduction efficiencies. Secondary (low and high) air ensures even air distribution over the char bed for pyrolysis and volatiles burning. NCG gas can be mixed with high secondary air, which provides air to the start-up burners. Tertiary air is the over-fire air over black liquor sprays and provides air to load-carrying burners. Finally, quaternary air is the air staging register at the upper furnace for NOx reduction. Moreover, the "Quaternary Air/Staged Combustion" technology employed on all modern recovery boiler systems already minimizes NO_X emissions while maintaining high reduction efficiencies, good bed stability, and uniform velocities.

6 Taconite – Four-Factor Feedback[18]

6.1 Overarching Taconite

At the MN taconite facilities, iron ore from mines along the Mesaba Iron Range is separated from taconite (a low-grade iron ore) using magnetism. The taconite powder with the iron in it is called concentrate which is rolled with clay inside large rotating cylinders. The cylinders cause the powder to roll into marble-sized balls that are then dried and heated until they are white hot. The balls become hard as they cool and become taconite pellets which are shipped to steel mills to be melted down into steel.[19]

On February 6, 2013, U.S. EPA promulgated a Taconite Regional Haze FIP that included BART limits for taconite furnaces subject to BART in Minnesota with an effective date of March 8, 2013.[20] On April 12, 2016, U.S. EPA finalized the revisions to the 2013 FIP and the final rule (2016 FIP) was effective on May 12, 2016.[21] EPA's 2016 FIP contained this:

> *We expect Minnesota and Michigan to reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods, but reject the technology as BART for the Minnesota and Michigan taconite facilities at this time.*

MPCA initially selected six taconite plants for four-factor analyses; their 2017 emissions (from the National Emissions Inventory—NEI) are shown below. (All emissions except Hg are in ton/yr; Hg is in lb/yr.) These facilities are located between 85 and 150 km south of Voyageurs National Park and within 300 km of Isle Royale National Park, both Class I areas administered by the National Park Service (NPS).

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[18] MPCA responses to NPS feedback:
MPCA added additional detail to Section 2.3.5 regarding the current FIP limits applicable to the taconite companies and a comparison of reported emissions data for recent years. MPCA also added additional clarification to Section 2.6.1 regarding how the MPCA estimated the reductions due to the FIP limits.
MPCA appreciates the suggestion to consider potential emission reduction measures from a multi-pollutant perspective. MPCA believes that is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts.

[19] Taconite | Minnesota DNR (state.mn.us)
[20] See 78 Fed. Reg. 8706 (February 6, 2013).
[21] See 81 Fed. Reg. 21672 (April 12, 2016).

Table 17. Recent annual emissions from Minnesota Taconite facilities, NEI 2017

Facility Name	Hg, lb/yr	NO_x, tpy	PM10-PRI, tpy	PM25-PRI, tpy	SO_2, tpy	NO_x+ PM10+ SO_2, tpy	Distance to NPS Class I Area, km	(NO_x+ PM10+ SO_2)/d
Hibbing Taconite Co	149	3,981	1,567	400	824	6,372	100	64
ArcelorMittal Minorca Mine Inc	75	3,063	567	173	136	3,766	85	44
United Taconite LLC - Fairlane Plant	190	3,743	595	412	275	4,613	108	43
Northshore Mining Co–Silver Bay	22	2,169	461	327	1,539	4,169	147	28
US Steel Corp–Minntac	173	6,481	2,788	2,084	1,207	10,476	85	123
US Steel Corp–Keetac	90	5,009	533	411	533	6,075	109	56
Totals	700	24,446	6,511	3,807	4,514	35,471		358

Based on emissions relative to distance to NPS managed Class I areas, MN ranks #9 in the US, with the taconite facilities comprising more than half of those impacts. (The taconite plants alone would rank #22 as a "state."

MPCA subsequently decided that no four-factor analyses or emission reductions were required for any of these facilities. The paragraph below (United Taconite—Fairlane) is an example of MPCA's rationale from the draft SIP:

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

NPS review and analysis demonstrates that controls that are more effective than the current controls are technically feasible, cost-effective, and may be considered reasonable.

MPCA may also be relying upon two other issues related to the taconite companies:

- Analyses conducted by U.S. EPA that determined what emission reductions were BART for the indurating furnaces at taconite facilities in Minnesota, as discussed earlier in Section **Error! Reference source not found.** regarding sources that are effectively controlled are referenced and relied on. The BART analyses conducted by U.S. EPA were included in the Taconite Regional Haze FIPs promulgated in 2013 and 2016.
- According to MPCA, U.S. EPA and the Minnesota taconite facilities have been in continued settlement discussions since the promulgation of these FIPs, as discussed in SIP Section **Error! Reference source not found.**, most recently resulting in revisions to the FIP requirements for U.S. Steel–Minntac in 2020. While the MPCA is not included in

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

EPA's previous BART determinations are no longer current (some of the facilities may have changed fuel mixtures and/or pellet characteristics) and warrant revisiting, especially with respect to EPA's 2016 comments regarding SCR with reheat.

The ongoing negotiations among EPA and the Minnesota taconite facilities do not exempt the taconite facilities from review in this planning period. In its 11/01/2021 letter to Wyoming, EPA stated:

> *Wyoming states that it did not conduct a four-factor analysis for the Wyodak facility due to ongoing first planning period litigation. First planning period litigation is not a basis to forego a four-factor analysis for Wyodak for the second regional haze implementation period. Wyoming must perform a four-factor analysis or provide a reasonable explanation for excluding Wyodak consistent with the Regional Haze Rule, EPA's Guidance, and the Clarifications Memo.*

6.2 United Taconite LLC–Fairlane Plant

6.2.1 Summary of NPS Recommendations for United Taconite LLC–Fairlane Plant

NPS review of the four-factor analysis conducted for Cleveland Cliffs' United Taconite—Fairlane Plant (UTAC) finds that NO_x, SO_2, and PM emissions from UTAC's Lines #1 & #2 are not effectively-controlled. Further, NPS review finds that:

- Application of tail-end SCR (installed after the existing wet scrubbers) at UTAC could cost-effectively reduce NO_x emissions by over 2,500 tons/yr.
- On their own, opportunities to reduce SO_2 emissions with a modern scrubber and fabric filter or ESP are well above the threshold for consideration even when adjusted for conformance with CCM methods. However, an integrated approach that precedes tail-end SCR with dry scrubbing and a fabric filter would minimize catalyst fouling (improving the technical feasibility of SCR) while drastically reducing PM emissions as well as reducing SO_2 emissions. This would be a far superior approach from an emissions reduction and cost effectiveness perspective with the potential to reduce haze causing emissions by thousands of tons per year in a cost-effective manner (Table 20).

The NPS recommends that MPCA require all taconite facilities originally selected for four-factor analysis to conduct four-factor analyses evaluating how an integrated approach to emission control improvements could reduce visibility-impairing emissions. Given both the scale and proximity of haze-causing emissions from taconite facilities, this may be the single best strategy available to MPCA for reducing haze-causing emissions and advancing incremental improvement of visibility at Voyageurs and Isle Royale National Parks as well as other Class I areas in the region.

6.2.2 Facility Characteristics

UTAC is located 108 km southwest of Voyageurs National Park. Of the six taconite facilities identified by MPCA for four-factor analysis, only Cleveland Cliffs submitted one for its UTAC plant. In that submittal, the company included this disclaimer:

> *The NOx Four-Factor analysis evaluated Selective Catalytic Reduction (SCR) with reheating of the exhaust gases using a conventional duct burner. It is important to note that the use of SCR with reheat has not been demonstrated on taconite furnaces or similar sources. Therefore, this technology does not meet the definition of technically feasible. However, according to EPA's 2016 Final Federal Implementation Plan (FIP),22 EPA expects Minnesota to reevaluate SCR with reheat as a potential option for reasonable progress in future planning periods. It is only due to this statement by EPA that the SCR with reheat control technology is included in the analysis; UTAC does not concur that SCR with reheat is considered technically feasible.23*

The NPS observes that, for the purposes of four factor analysis, a technology need not have been demonstrated on a specific industry to be "technically feasible"—it must only be available (which SCR is) and applicable (which SCR may be).

According to MPCA, lines 1 and 2 at UTAC were BART-eligible emission units and BART emission limits on NO_x and SO_2 were established by U.S. EPA in the Regional Haze Taconite FIP promulgated during the first Regional Haze Implementation Period. Lines 3, 4, and 5 can burn coal, petroleum coke, natural gas and distillate oil. These emission units utilize existing wet scrubbers for SO_2 control.

Emission units are subject to a NO_x emissions limit (1.5-3.0 lb NO_x/MMBtu for each line, fuel dependent, as a 30-day rolling average) established in the Taconite FIP dated April 12, 2016. These emission units required add-on controls, low-NO_x burners, to meet the NO_x limits.

Based upon data submitted by UTAC, annual average NO_x emission rates were 1,325 tons @ 1.83 lb/mmBtu for Line 1 and 1,874 tons @ 1.22 lb/mmBtu for Line 2. Additionally, these emission units are subject to an SO_2 emissions limit (529 lb SO_2/hr, averaged across both lines as a 30-day rolling average and a 1.50 percent sulfur content limit for any coal burned as a monthly block average) established in the Taconite FIP dated April 12, 2016. In the 2016 Taconite FIP, U.S. EPA determined that additional SO_2 controls were not economically reasonable and were not necessary for BART.

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[22] EPA April 12, 2016 Federal Register: We expect Minnesota and Michigan to reevaluate SCR with reheat as a potential option for making reasonable progress in future planning periods, but reject the technology as BART for the Minnesota and Michigan taconite facilities at this time.

[23] Regional Haze Four-Factor Analysis for NO_x and SO_2 Emissions Control
Line 1 Pellet Indurating Furnace EQUI 45/EU 040
Line 2 Pellet Indurating Furnace EQUI 47/EU 042
Prepared for United Taconite LLC – Fairlane Plant July 31, 2020

UTAC reports that the existing wet scrubbers are 25% effective at reducing SO_2. Based upon data submitted by UTAC, annual average SO_2 emission rates were 59.7 tons @ 0.08 lb/mmBtu for Line 1 and 215.4 tons at 0.18 lb/mmBtu for Line 2. The existing wet scrubbers are also 94% effective at reducing PM. (These NPS calculated values are based upon Appendix B of UTAC's four-factor estimate that Line 1 PM emissions are almost 1,500 tons/year and Line 2 PM emissions exceed 3,400 tons/year. MPCA reports that Line 2 emitted 94 tons of $PM_{2.5}$ in 2017.) Considering that modern particulate controls can remove 99.9% of emissions and modern SO_2 scrubbers can achieve up to 99% control, it is reasonable to conclude that more-effective controls for these pollutants may be feasible.

6.2.3 NO_x Four-factor Analysis

SCR – Post-Scrubber with Conventional Duct Burner Reheat

UTAC states that: According to EPA's 2016 Final FIP, a taconite facility in Sweden, LKAB, has implemented and operated an SCR with reheat through a conventional duct burner on a taconite indurating furnace. However, EPA has stated the following:

> *Alstom, the SCR vendor for LKAB, declined twice to bid on an SCR with reheat at Minntac, citing technical difficulties with the SCR with reheat at LKAB. These difficulties included operating within the narrow temperature range required by SCR with reheat. Further, LKAB is looking into process optimization and better burners to reduce NO_x as opposed to installing another SCR with reheat in the future.*

That information was specific to a different facility that burned different fuels over nine years ago and may very well be outdated or inapplicable. The NPS recommends contacting a SCR vendor regarding application to current UTAC operations.

UTAC also raises concerns regarding the application of SCR on taconite furnaces due to the differences from utility boilers with respect to gas composition, dust loading, and chemistry. Specifically, UTAC states that:

> *The most serious issues yet to be resolved with SCR on furnaces include the formation of SO3 in the reactor, the ability to inject ammonia at proper molar ratio under non-steady state conditions, the creation of visibility impairing pollutants, the increased oxidation of mercury, the creation of a detached plume, catalyst life, catalyst poisoning, fouling of the bed, and system resistance. Some of these issues, discussed in more detail below, could affect the validity of SCR with reheat control technology and would require extensive testing prior to installation and operation on an existing indurating furnace.*

Sulfur Dioxide and Sulfuric Acid

NPS review finds that the SO_2 concentrations in the gas stream exiting the existing 25%-efficient wet scrubbers is an order of magnitude lower than encountered by SCR on a typical coal-fired boiler. SCR in a tail-end configuration would also be exposed to much lower concentration of particulate and the reheated gas stream exiting the SCR would be well above the acid dewpoint.

NO_x Variability and Ammonia Slip

With respect to concerns raised by UTAC regarding NO_x variability and ammonia slip, the NPS notes that the reference cited is from 2006 and is based upon a high dust configuration SCR at a cement plant. As such it may not be relevant. Modern process controls and a much cleaner tail-end SCR location should be capable of better performance. The EPA Control Cost Manual (CCM) provides this more up-to-date information:

> *In the cement industry, pilot tests in the 1970s and 1990s showed that SCR could be a feasible control technology for cement kilns. Building on that experience, SCRs were first installed in Europe in 2001. Today, SCR has been successfully implemented at seven European cement plants in Solnhofer, Germany (operated from 2001 until 2006), Bergamo, Italy (2006), Sarchi, Italy (2007), Mergelstetten, Germany (2010), Rohrdorf, Germany (2011), Mannersdorf, Austria (2012), and Rezatto, Italy (2015). As of 2015, there is only one cement plant in the U.S. that has installed an SCR. This SCR began operation in 2013 and is installed after an electrostatic precipitator. The control efficiency for the system is reported to be about 80 percent, which is consistent with SCR applications on European kilns. SCRs have not seen widespread use in the U.S. cement industry mainly due to industry concerns regarding potential problems caused by high-dust levels and catalyst deactivation by high sulfur trioxide (SO3) concentrations from pyritic sulfur found in the raw materials used by U.S. cement plants. The SO3 could react with calcium oxide in the flue gas to form calcium sulfate and with ammonia to form ammonium bisulfate. The calcium sulfate could deactivate the catalyst, while the ammonium bisulfate could cause catalyst plugging. There have been concerns expressed about the potential for catalyst poisoning by sodium, potassium, and arsenic trioxide. Finally, other concerns expressed are that dioxins and furans may form in the SCR due to combustion gases remaining at temperatures between 450 degrees Fahrenheit (°F) and 750°F. These and other concerns regarding the implementation of SCR to the cement industry are discussed in detail in "Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns". Due to the small number of SCRs installed at cement plants, information on capital and operating costs for SCRs at cement plants is limited. The installation and operating costs for the SCR installed at the U.S. plant in 2013 are not publicly available at this time. In general, we expect the capital and operating costs would be higher than for low-dust applications due to the need to install catalyst cleaning equipment for SCR systems installed in high-dust configurations and for heating the flue gas in low-dust, tail-end configurations.*

Mercury Oxidation

UTAC raises mercury oxidation as a potential concern saying:

> *In the case of mercury, the SCR oxidizes mercury from its elemental form. Given the propensity for oxidized mercury to deposit near its emission point, the increase in mass of oxidized mercury emissions is expected to result in more local deposition (i.e., increased loading of mercury) and most certainly*

within northeast Minnesota. An increase in mercury loading to northeast Minnesota is inconsistent with the Statewide Mercury Total Maximum Daily Load (TMDL) study that requires a reduction in loading in order to reduce fish tissue mercury concentrations in the area. In addition, a wet scrubber would be required to control the oxidized mercury formed in the SCR.

NPS review finds that UTAC emitted 190 pounds of mercury in 2017, which ranked 49th highest in the US (2017 NEI). A co-benefit of SCR is its ability to oxidize elemental mercury to a form that is more-easily captured in follow-on controls. The NPS recommends that UTAC focus on the potential opportunity to reduce all forms of mercury emissions. Continued dispersion of mercury emissions over a wide area is a significant and ongoing concern for current controls.

Indurating Furnace Exhaust Dust

UTAC expressed concerns that constituents in the indurating furnace exhaust gas stream could adversely affect the SCR catalyst and increase adverse pollutant introduction to the exhaust stream. However, tail-end SCR being evaluated in this case is exposed to much lower concentrations of particulates and SO_2 than conventional SCR on a coal-fired boiler, for example.

The NPS appreciates that UTAC evaluated three SO_2 control scenarios that included enhanced particulate controls.

The advantages of tail-end SCR are described by the CCM:

An SCR reactor located downstream of the air heater, particulate control devices, and flue gas desulfurization (FGD) system ("low-dust" or "tail-end" configuration) is essentially dust- and sulfur-free but its temperature is generally below the acceptable range.
A tail-end system may have higher capital and operating costs than the other SCR systems because of the additional equipment and operational costs associated with flue gas reheating and heat recovery. However, these costs are in part offset by reductions in catalyst costs. Tail-end units require less catalyst because they can use catalysts with smaller pitch and higher surface area per unit volume. Tail-end SCR typically require only 2 layers of catalyst, although some use four half-layers of catalyst to allow for greater flexibility for catalyst replacement. In addition, because there is less fly ash, catalyst poisons, and SO_2 in the flue gas for tail-end units, the catalyst lifetime is significantly increased, and less expensive catalyst may be used. Some sources have reported catalyst lifetimes for tail-end SCRs to be over 100,000 hours. The tail-end SCRs may also have longer lifetimes due to the lower operating temperatures and lower levels of dust and SO3.

Addition of SCR with reheat in a tail-end configuration at UTAC would mitigate the concerns about catalyst fouling, poisoning, and degradation. Nevertheless, NPS analyses assumed tail-end SCR life of 20 years and catalyst life of 16,000 hours (the lower ends of the ranges recommended by the CCM for SCR on industrial boilers). NPS also applied the maximum recommended retrofit factor = 1.5. Considering the almost 5,000 tons of particulate emitted by

UTAC annually, the NPS recommends an integrated approach (as evaluated by UTAC and discussed in the SO_2 control section below) to reducing particulate, SO_2 and NO_x.

Statutory Factor 1: Cost of Compliance

NPS review finds that UTAC has overestimated the capital costs by overestimating the system heat input. Instead, NPS calculations included a 70%-efficient heat exchanger to reduce natural gas reheat requirements. Not only did this reduce operating costs dramatically, but the reduced system heat input also resulted in the much lower SCR capital costs.

The NPS evaluated the addition of SCR with reheat by making the following assumptions:

- Natural Gas = $3.90/scf (used by MPCA in other analyses)
- Urea 50% Solution = $1.66/gal (used by MPCA in other analyses)
- Estimated operating life of the catalyst ($H_{catalyst}$) = 16,000 hr (NPS used the lower end of the CCM catalyst life estimate due to the unproven nature of this application. UTAC assumed 8,000 hours which is less than the 16,000-hour lower end of the CCM range.)
- Catalyst cost ($CC_{replace}$) = $227/cf (CCM default) (UTAC used $248.05 based on inflating the CCM value. Instead, UTAC should use an actual, site-specific current value.)
- Interest Rate = 3.5% used by MPCA in other analyses--UTAC used a 4.75% interest rate.
- Markup on capital cost (Retrofit Factor) = 50% due to unproven application of SCR to taconite furnaces.
- Equipment Life = 20 years. NPS used the lower end of the CCM equipment life estimate due to the unproven application of SCR to taconite furnaces. (UTAC also used 20 years.)
- SCR Control Efficiency = 80% despite the clean, tail-end location with gas stream heated to CCM 650°F default. (UTAC used 50% based upon a 2006 report on SCR applied to cement kilns in a high-dust configuration.)
- The Chemical Engineering Plant Cost Index (CEPCI) for 2019 and used by MPCA was 607.5.

NPS analyses based SCR "Data Inputs" on the following:

- Maximum heat input rate (QB)
    - In addition to the heat input (190 mmBtu/hr for Line 1 and 400 mmBtu/hr for Line 2) from the induration furnace burners, the heat input from the duct burners that would be added to reheat the gas stream exiting the existing wet scrubbers (at 140°F for Line 1 and 136°F for Line 2) was included. NPS applied the Auxiliary Fuel Use Equation 2.21 from CCM 7th Ed November 2017 - Chapter 2 Incinerators and Oxidizers and estimated the additional duct burner heat input required to raise the SCR inlet temperature to 650°F (the CCM default value). Addition of a 70% efficient heat exchanger to reduce natural gas use was assumed. An additional 1,771 scfm gas is estimated as necessary to reheat Line 1 and 3,587 scfm for Line 2. The induration furnace + reheat total heat input rate

is estimated to = 400 mmBtu/hr for Line 1 and 622 mmBtu/hr for Line 2. These heat input rates are critical parameters in estimating the capital costs of the SCR systems.
    - UTAC did not include a heat exchanger.
    - UTAC also assumed that the SCR inlet temperature should be raised to 800^{o}F instead of the 650^{o}F CCM default or 730^{o}F optimum temperature; these assumptions raised natural gas use and costs unnecessarily.
    - UTAC's assumptions resulted in a more than three-fold increase in natural gas use compared to NPS estimates.
    - The resulting higher natural gas requirement led to UTAC estimates for heat input rate = 2,197 mmBtu/hr for Line 1 and 4,555 mmBtu/hr for Line 2. SCR capital costs for natural gas-fired industrial applications are directly proportional to the heat input rate. As a result of UTAC's overestimates for this parameter, its capital costs are overestimated by an additional 5–7 times.
- Inlet NO_x Emissions (NO_{xin}) to SCR:
    - NPS assumed that the duct burner would emit NO_x @ 0.1 lb/mmBtu based upon Alternative Control Techniques Document—NO Emissions from Stationary Gas Turbines, U. S. EPA 1/1/1993. The duct burner NO_x emissions were added to the induration furnace NO_x emissions and divided by sums of their heat inputs to estimate the uncontrolled NO_x emission rate = 1.20 lb/mmBtu for Line 1 and 0.91 lb/mmBtu for Line 2.
    - UTAC estimated uncontrolled NO_x emission rate = 0.16 lb/mmBtu for Line 1 and 0.11 lb/mmBtu for Line 2.
- Estimated actual annual fuel consumption?
    - NPS adjusted the heat input to yield the uncontrolled NO_x emissions estimated as described above.
    - UTAC appears to have used a similar method to estimate the same annual uncontrolled NO_x emissions.

Reheat costs were estimated as follows:

- CCM Table 2.10: Capital Cost Factors for Thermal and Catalytic oxidizers with Eqn. 2.34
- CCM Table 2.12: Annual Costs for Thermal and Catalytic oxidizers assumed a 19.0" H_2O pressure drop across the heat exchanger per CCM Table 2.13. This added $0.8 million and $1.8 million in annual electricity costs to Lines 1 and 2, respectively.

The table below shows the cost elements of adding SCR with reheat to each line.

Table 18. NPS estimated SCR + Reheat costs for UTAC Line 1 & 2 compared to UTAC estimates

SCR + Reheat	UTAC Line 1		UTAC Line 2	
	NPS	UTAC	NPS	UTAC
Capacity (mmBtu/hr)	300	2,197	622	4,455
Retrofit factor	1.5	1.6	1.5	1.6
CEPCI	607.5	607.5	607.5	607.5
Capital Cost	$12,064,772	$43,637,895	$18,600,939	$72,550,865
Interest rate (%)	3.50	5.5	3.50	5.5
Control Equipment Life (yr)	20	20	20	20
Capital Recovery Cost	$849,286	$3,652,470	$1,309,418	$5,500,301
Reheat Indirect Annual Cost	$262,785	$90,349	310,139	$106,540
Indirect Cost/Fixed O&M	$980,974	$3,772,408	$1,463,167	$6,182,554
Reheat Direct Annual Cost	$4,678,480	$15,468,890	$10,738,805	$31,434,467
Catalyst Life (hr)	16,000	8,000	16,000	8,000
Catalyst Replacement Cost	$85,076	$763,512	$163,129	$1,523,872
Direct Cost/Variable O&M	$5,398,834	$17,578,490	$11,847,347	$35,153,534
Total Annual Cost	$6,379,808	$21,350,897	$13,310,515	$41,336,088
Uncontrolled NO_x Emissions (Tons/yr)	1324	1325	1876	1874
Uncontrolled NO_x Emission Rate (lb/mmBtu)	1.83	0.16	1.22	0.11
NO_x Removal Efficiency (%)	80	50	80	50
Controlled NO_x Emission Rate (lb/mmBtu)	0.24	0.08	0.18	0.06
Net Tons Removed	1,052	663	1484	937
Cost-Effectiveness	$6,065	$32,228	$8,967	$44,115

A major factor in the difference between NPS estimates and those provided by UTAC is the addition of a 70% efficient heat exchanger to reduce natural gas consumption. This relatively small additional capital investment (Reheat Indirect Annual Cost) dramatically reduces natural gas consumption (Reheat Direct Annual Cost) and the capital cost of the SCR. The lower capital recovery cost and the lower operating costs result in much lower annual operating costs. Coupled with higher SCR control efficiency, the result is cost-effectiveness of $6,000/ton for SCR on Line 1 and $9,000/ton on Line 2. SCR on Line 1 is cost-effective when compared to MPCA's $7,600/ton acceptance threshold, while SCR on Line 2 is cost-effective when compared to the acceptance thresholds set by CO, NV, and OR.

Statutory Factor 2: Time Necessary for Compliance

According to UTAC, a state SIP revision is needed to approve a new statistically derived emissions limit methodology based on the emission performance of the new system, e.g. 99 percent UPL. Barr assumes that the revisions would occur within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023). After the SIP is promulgated, the technology would require significant resources and a time period of approximately five years to engineer, permit, and install the equipment.

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

Energy usage is most appropriately accounted for in the Cost of Compliance analysis. The other non-air quality environmental impacts cited are not unique to this site.

Statutory Factor 4: Remaining Useful Life

The CCM recommends a useful life of 20–25 years for SCR on industrial boilers.

6.2.4 SO_2 Four-factor Analysis

Control Selection & Efficiency

EPA's February 2013 BART determinations are now out-of-date and should be revisited for PM and SO_2 in addition to NO_x. UTAQ included analyses of strategies to reduce SO_2 emissions from Line 2:

Dry Sorbent Injection (DSI) – With New PM Control

While DSI has not been demonstrated at an operating taconite indurating furnace, DSI could conceptually be utilized if UTAC were to replace its existing PM controls (wet scrubbers) with controls that are compatible with DSI (e.g., baghouse or electrostatic precipitator (ESP)). Indurating furnace waste gas streams are high in water content and are exhausted at or near dew points. Gases leaving the indurating furnace are currently treated for removal of particulate matter using a wet scrubber. The exhaust temperature is typically in the range of 100°F to 150°F and is saturated with water. For comparison, a utility boiler exhaust operates at 350°F or higher and is not saturated with water. The indurating furnace waste gas conditions following the existing wet scrubber would plug both the filters and the dust removal system. Therefore, the proposed control train would need to replace the existing wet scrubber with DSI and new PM control. With the removal of the existing wet scrubber and addition of new PM control after the DSI, the DSI control technology is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

The DSI evaluation conclusions vary in past SO_2 control equipment evaluations (2006 BART, 2010 Keetac BACT, 2011 Essar BACT reports, and 2012 EPA BART Determination). The 2006 BART reports and 2012 EPA BART Determination evaluated DSI after the existing scrubbers and concluded that the technology was not technically feasible due to high moisture flue gas resulting in caking and blinding of the associated filter bags. The 2010 Keetac BACT and 2011 Essar BACT reports concluded that DSI was technically feasible but concluded that a GSA was BACT with a baghouse for PM control.

Spray Dry Absorption (SDA) – With New PM Control

While an SDA has not been demonstrated at an operating taconite indurating furnace, an SDA could conceptually be utilized if UTAC were to replaces its existing PM controls (wet scrubbers) with controls that are compatible with an SDA (e.g., baghouse or ESP). Similar to the DSI control option, the moisture in the exhaust stream after the existing wet scrubber would plug the dust collection system. Due to the saturated waste gas exhaust, the proposed SDA control technology would require replacement of the wet scrubber with an ESP ahead of the SDA with baghouse control. Therefore, SDA with new PM control is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

The SDA evaluation conclusions vary in past SO_2 control equipment evaluations (2006 BART, 2010 Keetac BACT, 2011 Essar BACT reports, and 2012 EPA BART Determination). All of the facilities' 2006 BART reports (except Northshore Mining Company (NSM) due to NSM already employing wet ESP control technology) and the 2012 EPA BART Determination concluded that SDA was not technically feasible due to the high moisture flue gas. NSM's 2006 BART reports concluded that SDA was not cost-effective on a $/ton removed basis. The 2010 Keetac BACT report concluded that SDA was technically feasible but stated that GSA was BACT with a baghouse for PM control. The 2011 Essar BACT report concluded that SDA was not cost-effective on a $/ton removed basis.

Gas Suspension Absorption (GSA) – With New PM Control

While GSA has not been demonstrated at an operating taconite indurating furnace, there are not strong technical reasons prohibiting the installation and operation at an indurating furnace if alternative PM controls are used instead of wet scrubbers (e.g., baghouse or ESP). Similar to the DSI and SDA control options, the moisture in the exhaust stream would plug the dust collection system. Due to the saturated waste gas exhaust following the wet scrubber, the proposed GSA control technology would require replacement of the wet scrubber with an ESP ahead of the GSA with baghouse control. Therefore, GSA with new PM control is assumed to be potentially technically feasible for Line 2 Indurating Furnace.

GSA was not assessed in the 2006 BART report. The 2010 Keetac BACT report concluded that GSA was technically feasible with a baghouse and was BACT. The 2011 Essar BACT report concluded that GSA was not cost-effective on a $/ton removed basis. There was an attempted application of GSA at a taconite pelletizing facility in 2018 in Indiana. The facility experienced severe operational issues with the GSA that resulted in an enforcement action for non-compliance, further supporting the uncertainty of the application of GSA on taconite indurating furnace. Regardless, UTAC proceeded to evaluate the control costs of a GSA for the purpose of this analysis.

Statutory Factor 1: Cost of Compliance

According to UTAC: The cost-effectiveness analysis compares the annualized cost of the emission control measure per ton of pollutant removed and is evaluated on a dollar per ton basis using the annual cost (annualized capital cost plus annual operating costs) divided by the annual emissions reduction (tons) achieved by the control device. For purposes of this screening evaluation consistent with the typical approach described in the EPA Control Cost Manual, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.5 percent interest is assumed in annualizing capital costs. The resulting cost-effectiveness calculations are summarized in UTAC Table 6-2.

Table 19. UTAC Table 6-2: SO_2 Control Cost Summary, Line 2 Indurating Furnace

Additional Emission Control Measure	Installed Capital Cost ($MM)	Annual Operating Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost-effectiveness ($/ton)
DSI with New PM Control	$50,466,157	$10,090,749	108.2	$93,300
SDA with New PM Control	$120,947,748	$19,573,967	108.2	$180,891
GSA with New PM Control	$113,793,152	$18,757,651	108.2	$173,347

NPS review finds several areas in which the UTAC cost analyses deviates from CCM recommended methods:

- 5.5% interest rate instead of 3.5% used by MPCA in other analyses.
- 20-year life instead of 30 years recommended by the CCM
- 50% SO_2 control efficiency instead of 95% for SDA (CCM) or GSA

Statutory Factor 2: Time Necessary for Compliance

According to UTAC: A state SIP revision is needed to approve a new statistically derived emissions limit methodology based on the emission performance of the new system, e.g. 99 percent UPL. Barr assumes that the revisions would occur within 12 to 18 months after the MPCA submits its regional haze SIP for the second implementation period (approximately 2022 to 2023). After the SIP is promulgated, the technology would require significant resources and a time period of approximately five years to engineer, permit, and install the equipment.

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

Energy usage and costs associated with solid waste handling and disposal are most appropriately accounted for in the Cost of Compliance analysis.

Statutory Factor 4: Remaining Useful Life

The CCM recommends 30 years for scrubber life.

6.2.5 PM Four Factor Analysis

Particulate emission reductions were not considered.

UTAC states that the existing wet scrubbers are 94% effective at reducing PM. NPS calculations based upon Appendix B of UTAC's four factor estimate that Line 1 PM emissions are almost 1,500 tpy and Line 2 PM emissions exceed 3,400 tpy. (MPCA indicates that Line 2 emitted 94 tons of $PM_{2.5}$ in 2017.)

According to the CCM, modern fabric filter baghouses and ESPs can remove at least 99.9% of particulate matter. Compared to the existing PM controls, a new baghouse or ESP could reduce annual PM emissions from Line 1 by 1,472 tons and Line 2 by 3,347 tons.

INTEGRATED MULTI-POLLUTANT STRATEGY

UTAC evaluated replacing the existing wet scrubber on Line 2 with a modern SO_2 scrubber and fabric filter or ESP. Although tail-end SCR with reheat may be technically-feasible when installed after the existing wet scrubbers, an integrated approach that precedes it with dry scrubbing and a fabric filter would minimize catalyst fouling (improving the technical feasibility of SCR) while drastically reducing PM emissions as well as reducing SO_2 emissions. The table below illustrates how such an integrated approach could reduce visibility-impairing emissions by thousands of tons per year in a cost-effective manner.

Table 20. NPS control cost estimates for an integrated approach to UTAC emissions

UTAC Fairlane Plant	Line 1	Line 2
Total Annual Cost (GSA+ESP+FF+SCR)	?	$ 28,783,891
Tons NO_x Removed	1,052	1,484
Tons PM removed	1,472	3,347
Tons SO_2 Removed	16	145
Total Tons Removed	2,540	4,976
Cost-Effectiveness ($/ton)	?	$ 5,785

MPCA Response to NPS Feedback

> *MPCA appreciates the suggestion to consider potential emission reduction measures from a multi-pollutant perspective. MPCA believes that is a larger undertaking than can be reasonably completed between the end of the FLM consultation period and the start of the public notice period but will consider this idea as part of future regional haze planning efforts.*

6.2.6 NPS Conclusions and Recommendations United Taconite LLC–Fairlane Plant

NPS review finds that NO_x, SO_2, and PM emissions from UTAC's Lines #1 & #2 are not effectively-controlled. For example, tail-end SCR could reduce NO_x emissions by over 2,500 tons/yr for $6,000–$9,000/ton. MPCA should require SCR on UTAC lines #1 & #2.

An integrated approach to Line 2 emissions could yield combined emission reductions of almost 5,000 tons/yr at a cost of $29 million/yr for a cost-effectiveness value of $5,800/ton.

The NPS recommends that MPCA explore this opportunity to substantively address the haze-causing emissions from UTAC and other taconite facilities in Minnesota through the regional haze process.